La Capra Associates

FEASIBILITY STUDY RELATING TO THE RENEWABLE PORTFOLIO STANDARD

Technical Report

PREPARED FOR

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TABLE OF CONTENTS

Introduction

The Massachusetts Department of Energy Resources (DOER) commissioned La Capra Associates, Inc. to assist them with assessing the feasibility of instituting certain proposed requirements for Renewable Portfolio Standards (RPS) eligibility as set forth in Section 105(g) of the Green Communities Act of July 2, 2008 (the Act). The legislation requires DOER to study the feasibility of implementing Sections 105(c) and (e) and propose regulations for implementing these sections.

Section 105(g) reads:

> ***Section 105(g):*** *The department shall assess the feasibility of implementing subsections (c) and (e) and report its findings along with proposed regulations for implementing these subsections in accordance with section 12 of chapter 25A, on or before November 1, 2008.*

Section 105(c)—reproduced below—specifies how renewable energy imported into the ISO New England (ISO-NE) control area can qualify for the RPS. This report focuses on Section 105(c)(3) because it is a new provision. Sections 105(c)(1) and (2) are already institutionalized in DOER regulations.

> ***Section 105(c):*** *The delivery of renewable energy into the ISO-NE control area, as described in subsection (b), shall not qualify under the renewable portfolio standard, notwithstanding such delivery into the ISO-NE control area, unless the generator of such renewable energy: (1) initiates the import transaction pursuant to a spot market sale into the ISO-NE administered markets or under a bilateral sales contract with a purchaser of the renewable energy located in the ISO-NE control area by properly completing a North American Electric Reliability Corporation tag from the generator in the adjacent control area to either a node or zone in the ISO-NE control area; (2) complies with all ISO-NE rules and regulations required to schedule and deliver the renewable energy generating source's energy into the ISO-NE control area; and (3) <u>commits the renewable generating source as a committed capacity resource for the applicable annual period.</u>*

Section 105(e)—reproduced below—specifies that RPS credits shall be reduced by certain exports of energy from the ISO-NE control area.

> ***Section 105(e):*** *The renewable portfolio standard credit applicable to the eligible renewable energy as determined under subsection (d) shall be reduced by any exports of energy from the ISO-NE control area made by the person seeking renewable portfolio standard credit for such renewable energy or any affiliate of such person, or any other person under contract with such person to export energy from the ISO-NE control area and deliver such energy directly or indirectly to such person.*

This report provides DOER with a comprehensive view of the issues surrounding the feasibility of Section 105(c) and 105(e). This report not only explores the technical feasibility of these requirements, but also evaluates the practical feasibility of implementing them, along with costs and benefits of various options. Also, the report creates a foundation for discussion by providing an overview of the capacity, energy, and Renewable Energy Certificates (REC) markets.

Definition of Feasibility

Section 105(g) requires DOER to determine whether the new RPS requirements are feasible. While there are numerous ways to define feasibility, this report explores two levels of feasibility:

- Technical feasibility
- Feasibility of implementation

Technical Feasibility: To be technically feasible, the existing market rules and/or processes in place and information available must be sufficient to implement Section 105(c), Section 105(e), or both. Minimal changes to existing processes might be needed, but they would not violate existing market rules. Also, renewable generators, subject to the requirements, will have opportunities to comply, whether they choose to or not.

Practical Feasibility of Implementation: Even if the requirements might be technically feasible to implement, there exist barriers that may prove either impractical to administer or impractical for generators to comply. This report explores specific option/s that DOER can consider in the implementation of the regulations to address such barriers.

Economic Implications: There are economic and market implications for parties involved that should be considered. These include:

- Potential of increased administrative costs and time for regulators, APX (the administrator of NEPOOL-GIS), and ISO-NE.
- Potential of increased costs, risks, and time for renewable generators (or market participants) to comply. Certain costs and risks can also adversely impact the ability for renewable generators to sign longer term contracts and to receive financing.
- Potential of reduced amounts of RECs available to meet the Massachusetts RPS, which may increase REC prices in the long-term.

As part of examining the issue of feasibility, DOER should also consider whether the proposed regulations achieve their intended economic benefits.

- Section 105(c) aims to increase the amount of capacity available to New England for resource adequacy. This could mean participating in the Forward Capacity Market (FCM), preferably bidding a low price and helping to reduce capacity and/or energy market costs.
- Section 105(e) aims to provide assurance that imported energy associated with a REC "stays" in New England and is not exported.

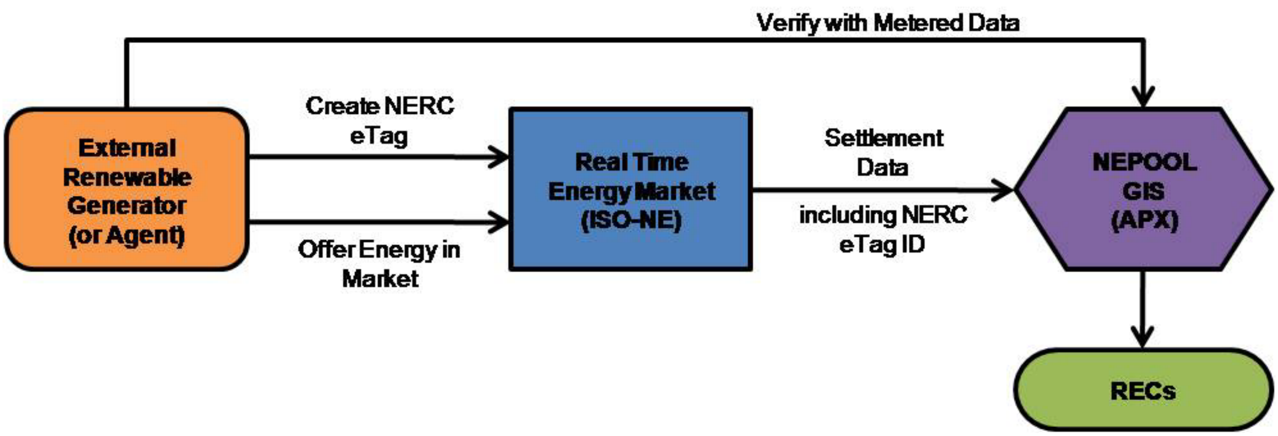
DOER can also consider a third aspect of feasibility — the legal feasibility of the disparate treatment of internal and external renewable generators. DOER will need to explore this issue separately as this report does not address the legality of these proposed requirements.

Part I: Primer on Markets

ISO-NE administers various capacity and energy markets. The Act can impact how renewable generators participate in these markets, including the Capacity Market—both during the transition period prior to the start of the Forward Capacity Market (FCM) and the FCM itself)—the Day Ahead Energy Market, and the Real Time Energy Market. Additionally, the Act will also impact how RECs are tracked through the NEPOOL Generation Information System (GIS).

Currently, most renewable generators,[1] whether in ISO-NE or delivering renewable energy to ISO-NE, participate in the Real Time Energy Market only. The figure below shows the typical renewable energy delivery and REC verification process for external renewable generators, currently.

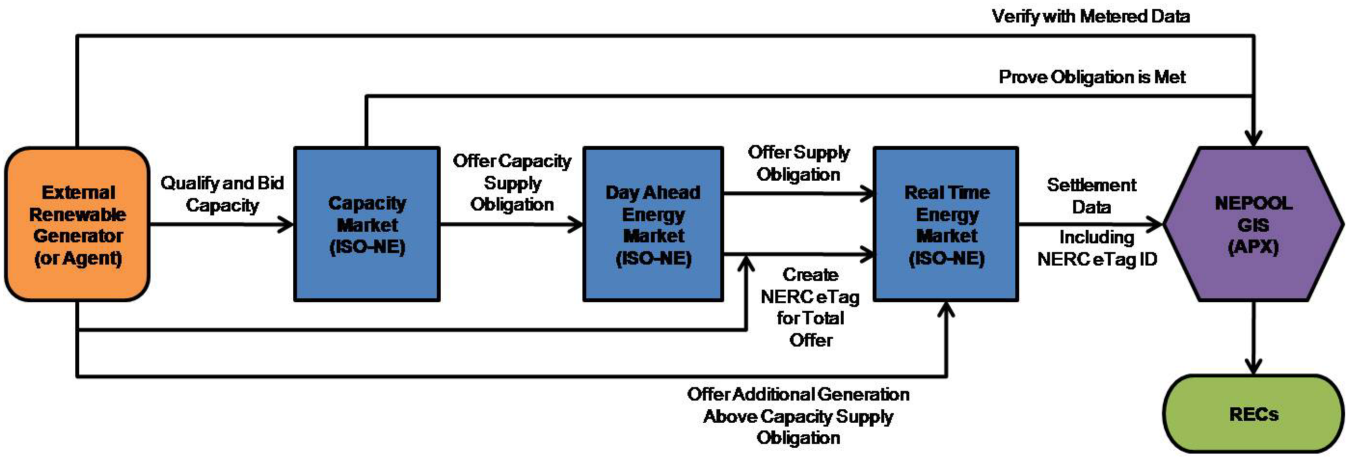
Figure 1: Current Process for Renewable Energy Imports



If Section 105(c) is implemented, renewable generators outside of ISO-NE may need to participate in two additional markets: the Capacity Market and the Day Ahead Energy market, as shown in the next figure. Resources that are participating in the Capacity Market are required to offer their capacity into the Day Ahead and Real Time Energy markets, in order to help ISO-NE better plan what generation to dispatch the next day.

[1] Certain small or behind-the-meter renewable generators may not participate in the market and can self-report or report via an independent verifier directly to the GIS.

Figure 2: Potential Renewable Energy Import Process if Participation in FCM is Required



The details of the participating in these markets and the paths participants need to take to satisfy the RPS renewable energy delivery requirements and the proposed requirements associated with Section 105(c) and 105(e) will be discussed in greater detail in Part I of this report.

I –1 Forward Capacity Market

Currently, providing capacity to ISO-NE is not a requirement for resources that are qualified or wish to qualify as Massachusetts RPS-eligible units. If Section 105(c) is implemented, it would require some commitment of capacity from external renewable generators but not from internal renewable generators (resources within ISO-NE). Specifically, imported renewable energy will only qualify if the "generator of such renewable energy commits the renewable generating source as a committed capacity resource for the applicable annual period." Though the language in Section 105(c) of the Act specifies that a resource needs to be a "committed capacity resource", this term is not defined anywhere in the Act and not defined in the ISO Tariff. The ISO Tariff does define a "capacity supply obligation" and a "capacity commitment period." One way for generators to be a committed capacity resources is to provide capacity to ISO-NE though its capacity market.

At the conceptual level, the focus of a capacity market is resource adequacy. It is designed to provide the electric system with adequate resources to meet the region's peak needs. This is done by procuring sufficient generating capability to meet the region's Installed Capacity Requirement (ICR). This requirement is based on the projected peak hour load for New England plus a reserve margin that ensures reliability.

Currently, ISO New England (ISO-NE) procures capacity though the installed Capacity (ICAP) planning and procurement process that pays a fixed kilowatt-month (kW-month) charge per month for qualified capacity from existing capacity resources.

Beginning in June of 2010, capacity will be provided through the Forward Capacity Market (FCM). It is called a "forward" market because auctions occur about 3-years prior to when the capacity will be procured and may include "new" resources that have not been built yet. Rules and regulations for participating in the FCM are described in Section III.13 of ISO New England FERC Electric Tariff No. 3 (ISO Tariff). According to the ISO Tariff, a number of different types of resources, including generation, demand, and imports[2] can provide capacity to meet New England's reliability needs.

This chapter discusses the current definitions, requirements, and procedures involved in participating in the FCM. We also report on the results of the first forward capacity auction (FCA) and provide some data from resources that were qualified for the second FCA to be held in December 2008.

1.1. Transition Period Prior to Forward Capacity Market

SECTION HIGHLIGHTS

- *During the transition period (December 2006 through May 2010), ISO-NE purchases capacity (on the behalf of load) from all existing qualified capacity resources, rather than purchasing the amount needed to meet reliability requirements.*
- *There are two ICAP Capacity commitment periods per year—summer and winter.*
- *Imports are limited to the amount of available import rights and requests are granted on a first-come, first-serve basis.*
- *Historically, the amount of "requested" import rights has often exceeded the "available" import rights across each interface.*

It is possible that DOER may consider promulgating regulations for implementation prior to June 1, 2010, the start of the first commitment period for the Forward Capacity Market (FCM). Thus, the section briefly discusses the commitment of capacity during the transition period prior to June 2010. Currently, capacity is procured through purchase of installed capacity (ICAP) during a transition period that runs from December 2006 through May 2010. In the transition period prior to the start of the FCM, the ISO purchases capacity (on the behalf of load) from all qualified capacity resources, rather than purchasing the amount needed to meet reliability requirements. As a result, purchases of capacity (and resulting capacity payments) may exceed levels that would normally be procured to maintain reliability levels. For example, in March of 2008, 38,212 MW of capacity received ICAP supply payments compared to 32,305 MW procured in the first capacity auction for the forward capacity market.[3]

During the transition period, there are two ICAP Capacity commitment periods per year—a summer commitment period that runs June through September and a winter commitment period that runs October through May. Payments, except for other demand

[2] Import resources can be supplied either by specific generating resources (but not a demand resource) outside the region that is owned or under contract, or supplied by control-area resources without specification to particular assets.

[3] Monthly Market Operations Report, August 2008, ISO-NE.

resources, are based on unforced capacity (UCAP) data[4], which reflects generators' dependable capacity adjusted by unplanned factors that impact actual availability, multiplied by a per kW-month fee. [5]

In-region generators have to be listed as an ICAP resource for the entire commitment period in order to receive ICAP payments.[6] By contrast, ICAP import contracts[7] (known as "external resources" during the transition period) are for two consecutive months at a time in the same commitment period. Import contracts can be backed by either an external resource or a control area. Imports are limited to the amount of available import rights, which vary by month during the transition period, and requests are granted on a first-come, first-serve basis, assuming that the request is not rejected by the ISO-NE. Based on the historical levels of import rights that have been granted, the amounts vary drastically from month to month and thus would make it difficult for an import to meet its "annual" commitment. The figure below shows the level of imports by external interface[8] (and the volatility due to changing import rights availability).

[4] Though the process is called ICAP procurement, the actual product being procured is unforced capacity (UCAP), which is seasonal claimed capability (or maximum dependable load-carrying ability) of the resource adjusted for unforced outages.

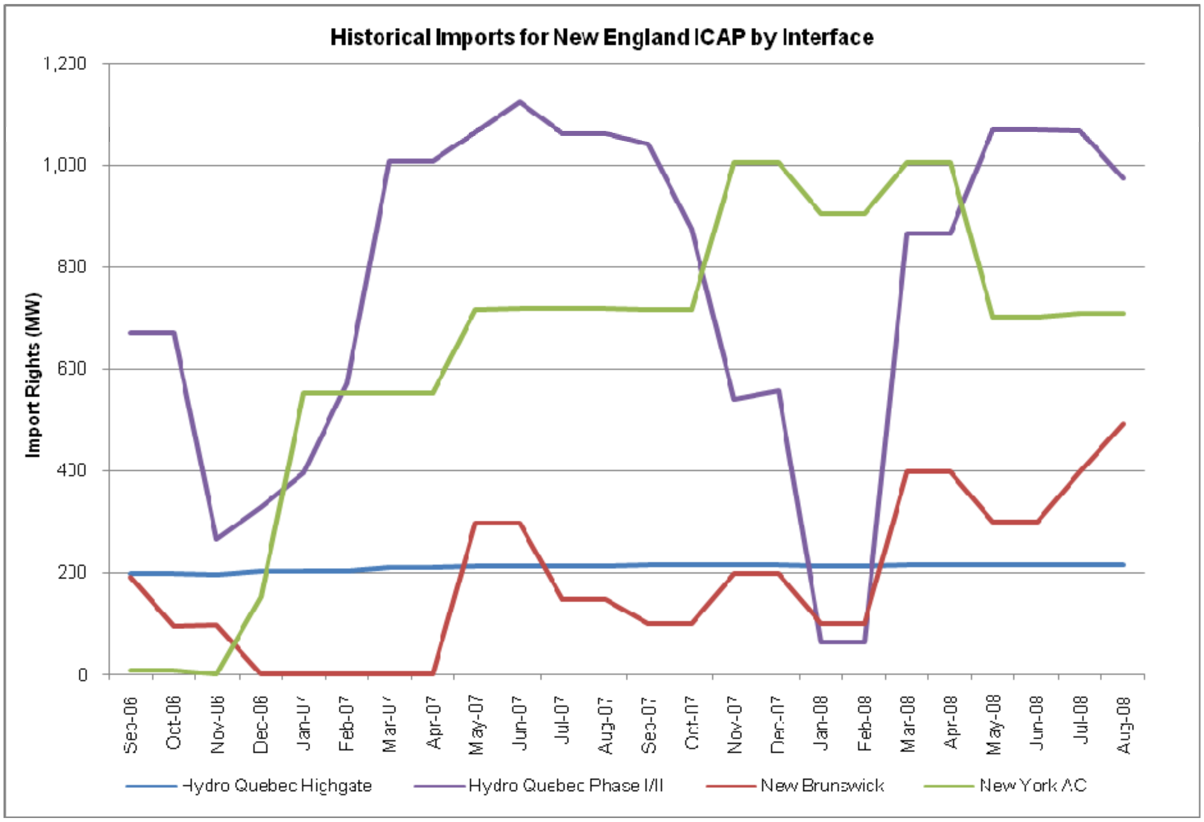
[5] Per Market Rule 1, per kW-month rates are fixed according to the following schedule: December 1, 2006–May 31, 2008 $3.05/kW-month, June 1, 2008–May 31, 2009 $3.75/kW-month, and June 1, 2009–May 31, 2010 $4.10/kW-month

[6] Resources submit planned outage schedules to the ISO for approval in order to be considered as an ICAP resource for an ICAP commitment period. Resources also submit operating data to the ISO every month in order to determine their actual UCAP ratings and payments.

[7] ICAP contracts are defined in the ISO tariff as "a contract for importing Installed Capacity from an external Control Area as described in Section III.8.3.7 of this Market Rule." Section III.8.3.7.2 of the ISO Tariff discusses performance of ICAP contract and states, "An ICAP Contract represents a commitment by the submitting party to offer and supply firm energy to the ISO-NE Control Area from resources located in an external Control Area."

[8] The Cross Sound Cable into Long Island in not shown since only exports are scheduled over this interface.

Figure 3: New England Historical ICAP Imports



Source: ISO-NE

Except for the Highgate facilities, there is some variation in the monthly amount of import ICAP (as measured by MW of unforced capacity) that receives transition payments. This variation is due to the availability of import rights on the lines after accounting for tie benefits, which can vary based on the season or month. The amount of capacity purchased over the Phase I/II interconnection is limited to the difference between the capacity transfer limits of the facilities and the level of Hydro Quebec Interconnection Capability Credits (HQICC), which represent the tie benefits over that facility. The amount of capacity purchased over other interfaces is limited to that interface's capacity limit minus any tie benefits.

Table 1 shows the available import rights for October 2008 (as of September 18, 2008). Historically, the amount of "requested" import rights has often exceeded the "available" import rights across each interface. As the table shows, a large number of requested imports were not granted by the ISO.[9] Requests can be denied if the tie lines are fully subscribed.

[9] Requests can be denied due to a number of reasons, including incomplete or inaccurate information, such as not naming or providing sufficient documentation concerning the unit or control are backing the import, or not meeting the ICAP contract requirement of two consecutive months.

Table 1: October 2008 ICAP Import Rights

Tie Line	Available Import Rights	Requested Import Rights	Granted Import Rights
Highgate	0	11	0
HQ Phase I/II	1750	1700	783
New Brunswick	500	1300	400
New York	702	1570	701

Source: ISO-NE

Bidding and scheduling requirements for ICAP resources in the energy markets are similar for both in-region and import contracts—these resources must offer their maximum dependable generation in both the Day Ahead and Real Time energy markets. The one exception is in-region intermittent resources, such as wind and solar, that does not have to offer their ICAP obligation in the Day Ahead energy market. (These requirements and distinctions between intermittent and non-intermittent generating resources are similar to those found for the FCM and thus will be discussed in greater detail in later sections.)

Since all in-region resources currently receive UCAP payments by virtue of being in the region, it is likely that a majority, if not all, of current in-region RPS-qualified renewable resources have capacity commitments through the end of the transition period. On the other hand, it is not possible to identify which ICAP import resources or contracts are renewable resources, since the recipients are not publicly identified by ISO-NE.

1.2. Forward Capacity Auction

SECTION HIGHLIGHTS

- *Capacity resources must bid and clear in a Forward Capacity Auction (FCA), wherein a certain amount of capacity is procured equal to the net ICR*
- *Each FCA is a descending clock auction with multiple rounds.*
- *In the first three auctions, there is a floor 0.6 x CONE for the clearing price; thus it may be possible that more resources than needed would remain in the auction.*

The Forward Capacity Market (FCM), unlike the transition period ICAP purchases, procures capacity some years in advance though an auction process. The first Forward Capacity Auction (FCA1) was conducted in February 2008 and procured resources that will be available to provide capacity by June 1, 2010. Subsequent auctions will eventually be procuring capacity resources three years and four months in advance of the required delivery date (start of the capacity commitment period).

Another difference from the transition period is that resources must bid and clear an auction, wherein a certain MW amount of capacity is procured equal to net ICR (ICR minus HQICCs), in order to have a capacity supply obligation and receive capacity payments. Each FCA is a descending clock auction with multiple rounds. Each round features a start-of-round and an end-of-round price, with the first round starting at 2 times the Cost of New Entry (CONE)[10] and subsequent rounds featuring successively lower prices. As the price falls (because capacity supplied is greater than the net ICR level), resources may drop out of the auction if they deem the end-of-round price is not rich enough to make the investment that is necessary to proceed with the critical path schedule for project completion or to continue commercial operation. The auction is concluded when the capacity still in the auction is less than or equal to the net ICR level procured in the auction. The clearing price is the highest price at which this occurs. Thus, unlike the transition period, not all resources that participate in the auction will receive payments if there is a surplus of capacity compared to the procured amount. [11]

In the first three auctions, assuming successful auctions, there is a floor of 0.6 x CONE for the clearing price; thus it may be possible that more resources than needed would remain in the auction in order to receive a prorated portion of the total available revenues equal

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[10] CONE is reset each year based on the average prices of the previous three years' auction results. CONE for the first auction was set at $7.50/kw-month.

[11] For an existing resource, as long as a delist bid does not clear or the delist bid clears but the plant is deemed as necessary for reliability (unlikely for renewable resources seeking RPS qualification) the resource will assume a capacity supply obligation for the entire one-year capacity period relevant to that particular FCA. New capacity resources would clear if one of the submitted price-quantity offers were equal to or less than the auction clearing price.

to the floor price times the net ICR level procured. Those who are able to participate in these first three auctions have the advantage of receiving a guaranteed price of no less than the floor.

1.3. Types of Capacity Resources

SECTION HIGHLIGHTS

- *Existing and new resources are defined differently according to the type of resource (generating, demand, or import), but the basic distinction is whether the resource achieves commercial operation.*
- *Existing resources are essentially "price-takers", except if there is a de-list bid, while new resources can set the "clearing" price.*
- *The ISO Tariff specifically defines **import capacity resources** as originating from outside the ISO region.*
- *The ISO Tariff defines **generating resources** as not being an import or demand resource.*
- ***Intermittent power resources** are a subset of generating resources and, thus, exclude import resources.*
- *The ISO Tariff does not give deference to intermittent and non-intermittent import resources.*

1.3.1. Defining New and Existing Resources

It is important to distinguish between existing and new resources that participate in each auction. Existing and new resources are defined differently according to the type of resource (generating, demand, or import), but the basic distinction is whether the resource achieves commercial operation; if the resource has been counted as a capacity resource in the past by, for example, receiving ICAP or transition payments or clearing in a prior FCA, and has not been previously deactivated or retired, then the resource is considered existing. For import capacity resources, which are considered on a year-to-year basis, only import resources backed by multi-year contracts can be eligible to be considered as existing. The table below summarizes these distinctions.

New capacity resources must undergo a more thorough qualifying process, discussed in Section 1.4, before they are allowed to participate in the auction.

Table 2: Defining In-region Versus Import Capacity Resources

	In-Region Capacity Resources	Import Capacity Resources
Existing	▪ Resources achieved commercial operation ▪ Counted as a capacity resource in the past	▪ Resource is backed by multi-year contracts ▪ Proof of ownership or control over an existing external resource
New	▪ Projects not on-line yet or have not been counted as a capacity resource previously	▪ All other imports

1.3.2. Price Takers vs. Price Setters

In terms of bidding, existing resources are required to submit an offer during every round of the auction, and thus are essentially "price-takers"[12], while new resources can withdraw their capacity if prices fall below what they need to be economical or can set the "clearing" price.[13] As such, qualified RPS resources in the region that are currently "existing" resources, by definition, have capacity supply obligations, unless they choose to delist,[14] and thus would meet the requirements found in the Act.

There are certain conditions attached to the prices new resources can bid. New resources that bid below certain levels need to pass a market monitoring test by submitting information that justifies their "low bid". If the justification is not accepted, the prices will be removed from the auction, but their capacity will still be available to clear, which essentially makes them "price-takers" as well. New resources that fail to submit justification will be completely removed from the auction.

1.3.3. Defining Non-Intermittent, Intermittent, and Import Capacity Resources

Section 105(c) appears to apply only to import renewable generating sources. However, the FCM provides special treatment for intermittent resources in the ISO-NE control area, which would apply to a majority of renewable generation, but does not specify similar or equal treatment for imports that are intermittent.

The ISO-NE market rules distinguish between three types of in-region resources: generating resources, intermittent power resources, and demand resources. We will not discuss demand resource qualification or participation in the capacity markets. Renewable generating resources can be either intermittent or non-intermittent generators (in terms of technology). The ISO tariff does not refer to "non-intermittent generators"—they are all generating resources that are not intermittent.

The ISO Tariff specifically defines **import capacity resources** as originating outside the ISO region.[15] Both definitions (existing and new) of import capacity resources are presented as follows:

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[12] Existing resources can opt-out of the annual auction or permanently opt out by submitting a "de-list" bid that clears, passing a reliability impact determination by ISO, and, depending on the level of the de-list bid, by passing a market monitoring review by the ISO.

[13] De-list bids can also set the "clearing" price.

[14] A De-list bid is a bid offered by an existing generator to exit the market if the clearing price falls below the delist bid price..

[15] It is important to note that both definitions indicate that a "contract", rather than a generating resource or project, is the actual product that is determining the capacity resource. The term "contract" is not specifically defined in the ISO tariff and should be interpreted broadly—for example, as any agreement (including ownership or control of an asset) to deliver capacity. As we discuss in greater detail in later sections, import capacity resources can be supported by commitments from specific resources, be they through a contract to

> ***Existing:*** *"Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource…" (Section III.13.1.3.1)*

> ***New:*** *"Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Commitment Capacity Period… shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource." (Section III.13.1.3.4.)*

The ISO Tariff defines **generating resources**, with separate definitions for new and existing, though the types of resources excluded from the definition are the same. We show the new generating capacity resource definition below:

> *A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3.), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4. shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction…"* (Section III.13.1.1.1)[16].

This definition specifically precludes import capacity resources from being included as a generating capacity resource.

Though not specifically defined as such, intermittent power resources are frequently referenced as a subset of generating capacity resources. For example, Section III.13.1.1.2.5.1 of the ISO Tariff is titled "New Generation Capacity Resources Other Than Intermittent Power Resources…" and Section III.13.1.2.2.2 is titled "Existing Generation Capacity Resources that are Not Intermittent Power Resources…" Consequently, we can infer that non-intermittent generators are generating capacity resources that do not meet the definition of intermittent power resources and can be defined as "generating capacity resources other than intermittent power resources or intermittent settlement only resources[17]."

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supply capacity or actual ownership of a resource, or by commitments from a control area that has agreed to provide capacity to support any capacity supply obligation that may clear in the auction.

[16] The definition of Existing Generating Capacity Resource (Section III.13.1.2.1) similarly excludes existing and new import capacity resources.

[17] Settlement only resources are generators less than 5 MW and those that generally are not telemetered.

The ISO Tariff defines **intermittent power resources** as follows:

> *Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output (Section III.13.1.2.2.2 of the ISO Tariff)[18].*

Though this definition is specific for certain renewable technologies, it does allow some flexibility in its application. The Massachusetts RPS, as described in 225 CRM 14.00, allows the following fuels, resources, or technology to be eligible for RPS qualification:[19]

- Solar photovoltaic or solar thermal electric energy.
- Wind energy.
- Ocean thermal, wave or tidal energy.
- Fuel cells using an Eligible New Renewable Fuel.
- Landfill methane gas and anaerobic digester gas, provided that such gas is collected and conveyed directly to the Generation Unit without use of facilities used as common carriers of natural gas.
- Low-emission, advanced biomass power conversion technologies using an Eligible Biomass Fuel.

Solar and wind are explicitly included as intermittent resources in the ISO tariff definition. Ocean thermal, wave or tidal energy would also be included due to the inability to have control over the net output of these facilities. The remaining three technologies, fuel cells, landfill gas (LFG) and biomass, would appear to be non-intermittent, but as we show in greater detail later, ISO-NE has qualified a number of LFG and biomass projects as intermittent resources.

Thus, based on the prior inference that intermittent resources are generating resources and that the definition of generating resources excludes import resources, it follows that intermittent resources can likewise not be import capacity resources. In short, though intermittent resources, as defined in the ISO tariff, cannot be import capacity resources, and import capacity resources cannot be intermittent resources, as defined in the ISO tariff, import capacity resources can be supplied from any type of resource (except demand resources) including renewable and non-renewable generating resources. The ISO Tariff does not give deference to intermittent and non-intermittent external resources.

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[18] Intermittent power resources are also defined in the "Definitions" section of the ISO Tariff (Section III.1.3.). That definition also includes resources less than 5 MW as intermittent resources.

[19] Run-of-river hydro has been added in the Act as a Class II renewable resource.

Table 3 summarizes the above discussion by comparing the various types of capacity resources under which renewable resources seeking RPS qualification could participate in the forward capacity market.

Table 3: Intermittent In-region versus Import Capacity Resources

<table>
<tr><th></th><th>In-region Capacity Resources</th><th>Import Capacity Resources</th></tr>
<tr><td>Intermittent</td><td>▪ Wind
▪ Solar
▪ Run of River Hydro
▪ Renewable Resources that have no control over output (as determined by ISO)</td><td rowspan="2">▪ Capacity imports definition
▪ Single or multi-year contract to delivery capacity into New England from an external control area
▪ Can be backed by specific asset or resource or backed by control area
▪ Can be any type of generation but cannot be a demand resource.</td></tr>
<tr><td>Non-Intermittent (Generating)</td><td>▪ Generating capacity resources other than Intermittent</td></tr>
</table>

Over the next few sections, we discuss important distinctions among the different resources referenced in the ISO Tariff. The goal is not to provide a detailed analysis and description of the ISO Tariff for each resource type, but to point out differences in treatment found in the Tariff between in-region renewable resources and renewable resources associated with import capacity.

1.4. Qualification

SECTION HIGHLIGHTS

- *Existing generating resources do not need to qualify for participation in the auctions in the same way as new resources.*
- *Project sponsors for new resources need first to submit a show of interest and a refundable qualification process cost reimbursement ("qualification") deposit.*
- ***All new capacity resources** need to include a critical path schedule.*
- ***New intermittent generating resources** need to include a claimed summer and winter qualified capacity based on site-specific seasonal data that will support these claimed capacity values.*
- ***New import capacity resources** need to include some documentation of import capability, which can be resource-backed or system-backed.*
- ***Intermittent resources** have more flexibility in calculating and altering their qualified capacity levels.*
- *Project sponsors of new capacity resources, **except for new import capacity resources**, can elect a five-year capacity commitment at the FCA clearing price.*
- ***New import capacity resources** are always subject to rationing, which may occur, for example, if interface capacity transfer limits bind, but internal generators have the option to ration.*
- *Qualification in either the annual forward capacity auction or reconfiguration auction is required for resources if they wish to enter in bilateral contracts.*

The first step in taking on a capacity supply obligation for a capacity commitment period is to qualify for participation in either the annual forward capacity auction or one of the reconfiguration auctions. Qualification requirements differ based on whether capacity resources are considered new and existing, with new resources requiring much more proactive involvement on the part of project sponsors. The fact that existing resources face an easier time in qualifying for the FCA is not surprising, given that they represent "steel in the ground" and generally have a history of performance data to determine potential capacity contributions and qualified capacity levels.

1.4.1. Existing Resources Submit Qualification Package

Existing generating resources (except in the case of changes in qualified capacity levels including deactivation) do not need to qualify for participation in the auctions in the same way as new resources. Rather than submit show of interest forms (SOIs) or qualification packages to ISO, project sponsors are notified by ISO as to the resource's summer and winter qualified capacity values. Sponsors can challenge the ISO's determination. The qualification package is also the vehicle by which sponsors submit de-list bids or retirement requests. Unlike new capacity resources, existing capacity resources, including those that have cleared in a prior FCA, do not offer supply curves that describe the quantity of supply obligation the resource would take on and at what price. Rather, existing capacity resources are offered during all rounds (and prices) found in the FCA. The only ways for existing resources to opt out of the FCA are (1) to submit a de-list bid, which is a price and quantity pair indicating the amount of supply obligation that would be shed by the resource if the bid clears in the market, or (2) to submit a non-price retirement request. Both requests are subject to a review of reliability by the ISO and thus can be denied. The ISO recently submitted a proposal to FERC that describes compensation to units that submit de-list bids that clear the FCA or retirement requests but are still required for reliability purposes.[20]

Existing import capacity resources follow the same qualification procedures as existing generating resources but must also provide documentation of import, such as a multi-year contract or proof of ownership or direct control of the resource along with data to support summer and winter ratings.

1.4.2. New Resources Submit Show of Interest

Project sponsors for new resources need first to submit a show of interest (SOI) that contains a number of data elements, including project and contact information, expected commercial operation date, capacity of the resource, economic minimum limit, interconnection status and location, and documentation of site control, among other project data. (Section III. 13.1.1.2.1). SOIs are submitted well in advance of the start of the capacity commitment period. For example, the submittal window for new capacity SOIs for the capacity commitment period starting on June 1, 2013 is May 15, 2009 to July 14, 2009. The date for submittal of SOIs will be increasingly earlier until 2016, when the submission window for a capacity commitment period that starts in June is to be the November through January period that starts almost five years prior to the beginning of the commitment period. Project sponsors must submit a refundable qualification process cost reimbursement ("qualification") deposit with the SOI, which varies from $1,000 for import capacity resources to $25,000 for new generating resources greater than or equal to 20 MW (Section III.13.1.9.3 of the ISO Tariff).[21]

1.4.3. New Resources Submit Qualification Package

New capacity qualification packages are due five to six months following the SOI submittal. The contents of the qualification packages differ depending on the type of resource seeking to be qualified, but the overall purpose of the information submitted is to allow the ISO to assess the likelihood of commercial operation of the resource and approve a qualified capacity level that can be bid into the forward capacity market. A non-exhaustive overview of the data required from different resource types is provided below. The table below summarizes the information needed for new resources.

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[20] July 1st filing to the FERC. Docket No. er08-1209-000

[21] This deposit is to cover the costs of the ISO and its consultants associated with the qualification and critical path monitoring process. Actual costs will be billed to the project sponsor with unused funds returned and costs greater than the deposit billed. The deposit is refundable if projects are withdrawn before the capacity qualification deadline.

Table 4: Qualification Packages for New Non-Intermittent, Intermittent, and Import Resources

	Non-Intermittent	Intermittent	Import
New	▪ Submit critical path schedule		▪ Submit critical path schedule if backed by new (to be built) resource
	▪ Option to elect to have a 5-year obligation ▪ Option to elect to ration capacity		▪ Indicate the interface over which the capacity will be imported ▪ Include some documentation of import capability
	▪ ISO determines capacity commitment	▪ Claimed summer and winter qualified capacity based on site-specific summer and winter data (reviewed by ISO)	
Existing	Option to submit de-list bid		
	▪ Determined by ISO	▪ Determined by ISO	▪ Indicate the interface over which the capacity will be imported ▪ Include some documentation of import capability

- **New generating resources** need to include a critical path schedule in order for ISO to assess the feasibility of achieving the commercial operation date specified in the SOI, which can be no later than the start of the capacity commitment period.
- **New intermittent generating resources** also need to include a claimed summer and winter qualified capacity based on site-specific summer and winter data that will support these claimed capacity values.[22]
- **New import capacity resources** also need to indicate the interface over which the capacity will be imported; [23] and include some documentation of import capability, which can be resource or system-backed, such as
  - a one-year or multi-year contract to provide capacity (along with the MW value) from an external resource,

[22] Specifically, Section III.13.1.1.2.2.6 (b) of the ISO Tariff requires "measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources)…"

[23] There are additional requirements for imports that cross intervening control areas, but we do not discuss these here since the legislation only applies to adjacent control areas.

    - proof of ownership or direct control of the resource along with data to support summer and winter ratings, or
    - documentation from a control area if system-backed;
- If the import is backed by an existing resource or control area, then the critical path schedule and proof of site control are not required.

It is important to note that, except for intermittent resources, no reduction in capacity values in either the SOI or the qualification package are allowed between the date that is 150 days before the start of the relevant FCA and the date no later than 120 days prior to the FCA start, which is the date project sponsors are notified of their qualification status. Intermittent resources can have different values for capacity reduction values in the SOI compared to their qualification packages. In short, intermittent resources have more flexibility in calculating and altering their qualified capacity levels and can risk overestimating their qualified levels in their SOIs or qualification packages.

In addition to project-specific data to support summer and winter qualified ratings, qualification packages contain two other submittals that differ among the different capacity resource types. First, project sponsors of new capacity resources, except for new import capacity resources, can elect a five-year capacity commitment at the FCA clearing price. Thus, new resources unlike import capacity resources can lock in a revenue stream for five years. This ability is especially valuable if capacity prices are expected to decrease, which appears likely over the near term.

The second major difference relates to rationing. New capacity resources, except for new import capacity resources, may elect to ration their offers or bids in the FCA, thereby permitting a capacity supply obligation less than their offer. If this election is not made, offers must clear or not clear in whole. New import capacity resources are always subject to rationing, which may occur, for example, if interface capacity transfer limits bind.

1.4.4. New Resources Not Qualified for an FCA

For new resources that have not qualified for an FCA but wish to participate in the reconfiguration auctions, the timeline is different than discussed above. For those resources that have achieved commercial operation but have never qualified, an SOI must be submitted by the first business day in August prior to the reconfiguration auction; resources must qualify for an annual reconfiguration auction in order to participate in seasonal or monthly reconfiguration auctions. Resources are notified in the December following the August deadline of their qualification status. Qualification in either the annual forward capacity auction or reconfiguration auction is required for resources if they wish to enter in bilateral contracts. This discussion applies equally to all resource types.

1.5. Financial Risks of Market Participation

SECTION HIGHLIGHTS

- ***Existing resources*** *generally do not have to pay additional financial assurance to participate in the forward capacity markets*
- *The financial assurance applies to the amount of the awarded capacity, not the submitted or cleared capacity*
- *Total financial assurance for new capacity resources equals three times CONE times the awarded capacity supply obligation.*
- *Financial assurance requirements are identical for all capacity resource types that are considered* ***new****, except for new import capacity resources that are backed by existing resources or a control area.*
- *If a project sponsor is unable to achieve commercial operation by the start of the capacity commitment period, he would be able to transfer his capacity supply obligation to another entity until his project is running.*
- *The ISO has the right to terminate a resource's capacity supply obligation and not return financial assurance in the event that the resource has not achieved commercial operation after two capacity commitment periods.*

After qualification, resources become eligible to participate in the auctions or bilateral transactions by posting financial assurance, described in Section III.13.1.9 of the ISO Tariff. Existing resources generally do not have to pay additional financial assurance to participate in the forward capacity markets.[24] Prior to this point, the only financial risk to potential new capacity resources is the time and effort to complete the qualification requirements and the submittal of the qualification deposit. Once qualified, new capacity resources must post a financial assurance deposit[25] (as distinguished from the qualification deposit) equal to $2/kilowatt (kW) times the number of kilowatts qualified as new capacity.[26] If a project sponsor assumes a capacity supply obligation by clearing his capacity in the auction, this deposit will be applied to additional financial assurance requirements that are required later; if the sponsor's capacity does not clear, the deposit is returned upon timely request from the project sponsor.

Additional financial assurance depends on the price of the cost of new entry (CONE) for the relevant capacity commitment period. For the first capacity commitment period (June

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[24] Existing resources are generally sponsored by existing market participants who have participated and participate in current and past ISO markets, such as energy, reserves, and ICAP. Thus, they have already posted financial assurance to participate in these markets or procurements. Additional assurance for FCM is only needed if a unit is retired and has not transferred their capacity supply obligation to another resource or in the case of existing resources seeking to transfer their capacity supply obligation to another resource in a reconfiguration auction or through a bilateral transaction.

[25] Financial assurance can be in the form of cash, a letter of credit, or a corporate guaranty.

[26] This discussion is based on Section I, Exhibit 1A of the ISO-NE Tariff.

1, 2010 to May 31, 2011), CONE was $7.50/kW-month. Subsequent CONEs are a function of the CONE and clearing price from the prior auction.[27] CONE for the second commitment period is $6.00, and we expect the value for CONE for the third capacity commitment period to decline further.

Table 5 uses the qualification process and financial assurance timeline for FCA2 to show the amounts and timing of required financial assurance for a 100 MW wind facility with a 20 MW qualified capacity level, all of which is assumed to clear in the auction.

Project sponsors must post financial assurance three more times following the initial deposit submitted with the SOI. The financial assurance applies to the awarded MW of capacity, not the submitted capacity or the capacity qualified by the ISO. Therefore, in cases where capacity obligations are pro-rated downwards or bidders decrease bid quantities during the auction, the financial assurance is scaled down accordingly.

The first occurrence is five business days following the announcement of winning sponsors in the FCA and is equal to CONE multiplied by the kW of capacity awarded—as distinct from kW of capacity qualified—in the FCA minus the amount of the financial assurance deposit. Project sponsors must then post financial assurance equal to CONE multiplied by the awarded kW at least fifteen days prior to each of the next two FCAs after the FCA in which the sponsor's capacity cleared. Total financial assurance for new capacity resources equals three times CONE times the capacity supply obligation that cleared in the FCA. This total amount also applies to participation in the reconfiguration auctions and any bilateral transactions approved by the ISO, though the timeline for submitting the amount will depend on the particulars of the reconfiguration auction or bilateral transaction.

Following successful commercial operation and testing of resource at the capacity supply obligation levels, the financial assurance for new capacity resources is returned and the resource is treated as existing capacity in terms of the financial assurance policy. Upon request from the project sponsor, the ISO will return the difference between the new capacity financial assurance amount and the existing capacity amount. This difference can be substantial. As an example, for a generating facility with a 20 MW qualified capacity seeking to participate in the second FCA for the second capacity commitment period, the designated project sponsor would have to post $6 times 3 times 20,000 kW, which is equal to $360,000. This amount contrasts with typical initial financial assurance payments of under $20,000 for existing capacity resources with a similar capacity obligation.

[27] Assuming a successful auction; other rules apply if the auction is deemed unsuccessful.

Table 5: FCA2 Timeline Example

FCM Related Deadline Date	FCM Requirement	Financial Assurance *(Example of 100 MW Wind with 20MW of Capacity Supply Obligation)*
9/18/2007 - 11/14/2007	New Capacity Show of Interest Submission Window	
Late 12/2007 or early 1/2008	Pay Qualification Process Cost Reimbursement Deposit—Refundable if qualification package not submitted	$1,000 if import or $25,000[28] for projects >=20MW
03/14/08	Existing Capacity Qualification Deadline to submit Qualification Package	
04/29/08	New Capacity Qualification Deadline to submit Qualification Package	
08/01/08	Qualification Determination Notification for FCA.	
08/12/08	A Project Sponsor may withdraw from the qualification process at any time prior to three business days before the deadline for submission of the financial assurance deposit	
08/15/08	Provide Financial Assurance Deposit in the form of Qualified Capacity x $2/kW	$2 kW x Qualified Capacity = $2 x 20 MW x 1000 = $40,000
12/08/08	Conduct FCA—If no MW are awarded in the FCA, the financial assurance deposit is returned upon request	Awarded all 20 MW
12/2008	Deadline for Awarded First Installment of Financial Assurance	CONE x Qualified Capacity minus Qualification Process Cost Reimbursement Deposit = ($6 x 20 MW x 1000 kW = $120,000 - $40,000 = $80,000
Mid 9/2009	Deadline for Second Financial Assurance Payment	CONE x Awarded Capacity = $120,000
Mid 7/2010	Deadline for Third Financial Assurance Payment	CONE x Awarded Capacity = $120,000
6/1/2011	Capacity Commitment Period Begins If project is on-line, ISO-NE refunds financial assurance, except existing capacity financial assurance If project fails to meet on-line date, project sponsor must transfer the capacity supply obligation to a qualified capacity resource.	

Source: ISO-NE, La Capra Associates

Financial assurance requirements are identical for all capacity resource types that are considered new, except for new import capacity resources that are backed by existing resources or a control area. This latter group of resources follows the financial assurance requirements for existing resources. All new capacity resources are subject to having their financial assurance forfeited if the new capacity resource is unable to deliver any portion of the capacity supply obligation. There are ways to reduce one's capacity supply obligation, which we discuss below, and thus reduce or eliminate this loss of financial

[28] Projects with an executed feasibility study or system impact study agreement pay $15,000.

assurance. For example, if a project sponsor is unable to achieve commercial operation by the start of the capacity commitment period, he would be able to transfer his capacity supply obligation to another entity until his project is running.

However, there are limits to how long the ISO will accept delays, since the ISO has the right to terminate a resource's capacity supply obligation and not return financial assurance in the event that the resource has not achieved commercial operation after two capacity commitment periods following the start of the capacity commitment period for which the resource assumed a capacity supply obligation. In other words, the new capacity resource has two additional capacity periods to meet its obligation before ISO-NE can terminate the obligation and keep all financial assurance payments. Financial assurance can also be forfeited if the project sponsor fails to provide the assurance based on the schedule described above or if the project sponsor withdraws from ISO monitoring of the resource's critical path schedule.

1.6. Acquisition of Capacity Supply Obligation

SECTION HIGHLIGHTS

- *DOER will have to define and make clear the amount of "committed capacity" that would be required in order to qualify a set amount of generation for RPS eligibility.*
- *The next FCA where external renewable generators will be able to assume a capacity supply obligation is the fourth FCA (FCA4).*
- *For resources that did not submit SOIs in time for the annual auction or did not clear in any FCA, resources can seek to acquire a capacity supply obligation through reconfiguration auctions or bilateral contracts.*
- *To acquire a capacity supply obligation through a reconfiguration auction, there has to be either (a) projects with existing capacity supply obligations seeking to shed those obligations, or (b) ISO-NE submitting demand bids for capacity due to levels of ICR higher than the capacity obligated.*
- *To sign a bilateral contract, there has to be a resource with a capacity supply obligation that they wish to shed.*
- *Capacity load obligations cannot be offset with capacity supply obligations. Thus, a load serving entity with a load obligation and responsibility to pay capacity payments cannot address that responsibility by signing a contract with a capacity resource.*

A capacity supply obligation is defined in Section III.13 of the ISO Tariff as "an obligation to provide capacity from a resource, or a portion thereof, which is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5." Consequently, we discuss the acquisition of a capacity supply obligation through various mechanisms individually and what is required to become a "committed capacity resource for the applicable annual period", as described by the Act.

1.6.1. Commitment Quantity

Though Section 105(c) was clear in regards to the term of the capacity obligation (one year), it was unclear in terms of the quantity of the capacity supply obligation. The ISO Tariff specifies a minimum size for a capacity resource of 100 kW and if that resource clears any amount equal to or greater than 100kW in an annual or reconfiguration auction or signs a bilateral transaction that is approved by ISO-NE, it is has acquired a capacity supply obligation during the relevant commitment period. In addition, it is possible for a resource to clear in the auction but be prorated down to zero, meaning they still have a capacity supply obligation but it was reduced from their offer amount to zero by the ISO.[29]

Finally, since the ISO Tariff does not provide separate capacity capability (quantity) definitions for external intermittent and non-intermittent resources, DOER will have to define and make clear the amount of "committed capacity" that would be required in order to qualify a set amount of generation for RPS eligibility.

1.6.2. Annual Auction

The most certain, and currently only available, way to acquire a capacity supply obligation is to clear a supply offer in the annual auctions. There has been only one FCA to date with the second FCA to be held in December 2008. In a later section, we discuss the resources that cleared in the first FCA and those that are qualified to participate in the second FCA. The deadline for submittal of SOIs for participation in the third FCA (FCA3), which covers the 2011–2012 capacity commitment period, was September 16, 2008. Any capacity resource that is not yet built (or one that would achieve commercial operation by June 2011 but has never submitted any qualification materials) would have had to submit an SOI by that date. Otherwise, these resources will not be able to participate in the third FCA, which is currently scheduled for October 2009. The next FCA where these resources will be able to assume a capacity supply obligation is the fourth FCA (FCA4). FCA4 starts in June 2013, with SOIs due in mid-July of 2009.

1.6.3. Reconfiguration Auctions

For resources that did not submit SOIs in time for the annual auction or did not clear in any FCA, clearing in a reconfiguration auction is one way to acquire a capacity supply obligation. Three types of reconfiguration auctions will be held:

- **Annual:** For the first five capacity commitment periods, there will be two annual reconfiguration auctions prior to the start of the commitment period, with three auctions for capacity commitment periods starting in June of 2015. Capacity supply obligations acquired through the annual auctions are for the entire annual commitment period.
- **Seasonal:** There will be two seasonal auctions for each commitment period. Prior to the start of the capacity commitment period and the June monthly reconfiguration auction but after the last reconfiguration auction, there will be a summer seasonal reconfiguration auction. The winter seasonal reconfiguration auction will be held prior to October of the capacity commitment period and

[29] For example, the first FCA had excess supply of 268 MW over the Phase I/II HQ External Interface that cleared. This capacity supply obligation was prorated to zero MW.

prior to the October monthly reconfiguration auction. Capacity supply obligations acquired through the seasonal reconfiguration auction are only for that season (summer or winter) of the commitment period.

- **Monthly:** Prior to each month of the capacity commitment period, there will be monthly reconfiguration auctions for capacity supply obligations for that month.

Even though the ISO Tariff specifies that these reconfiguration auctions will be held, in order for a resource to acquire a capacity supply obligation through them, there has to be either (a) projects with existing capacity supply obligations seeking to shed those obligations by submitting demand bids, or (b) ISO-NE submitting demand bids for capacity due to levels of ICR higher than the capacity obligated. Table 6 summarizes the timing of the annual and reconfiguration auctions related to FCA2 and includes bilateral contracts (which are discussed in the following section).

Table 6: The Timing of Annual and Reconfiguration Auctions for FCA2

	Month/Year	Event
Bilateral Contracts Can Be Signed Anytime	December 2008	Forward Capacity Auction for Second Capacity Commitment Period
	April 2010	Second Annual Reconfiguration Auction
	April 2011	Third Annual Reconfiguration Auction
	April/May, 2011	Summer Seasonal Reconfiguration Auction
	May 2011	June Monthly Reconfiguration Auction
	June 1, 2011	Start of Second Capacity Commitment Period
	June 2011 to April 2012	July 2011 to May 2012 Monthly Reconfiguration Auctions
	May 31, 2012	End of Second Capacity Commitment Period

1.6.4. Bilateral Contracts

The final way to acquire a capacity supply obligation is to sign a bilateral contract with a resource that already has a capacity supply obligation that they wish to shed. Bilateral contracts can be signed anytime prior to and during the relevant capacity commitment period and must be submitted to ISO for approval. The acquiring resource would have to be qualified as described in the section above. Thus, bilateral supply obligation contracts can only be between resources seeking to shed an obligation and resources seeking to acquire an obligation. Capacity load obligations cannot be offset with capacity supply obligations. Thus, a load serving entity with a load obligation and responsibility to pay capacity payments cannot address that responsibility by signing a contract with a capacity resource, but they can shed their load obligation by transferring their obligation to a Market Participant seeking to acquire a load obligation. Bilateral contracts can be of one month to one year duration and must be for a minimum of 100 kW.

1.7. Capacity Supply Performance Requirements

SECTION HIGHLIGHTS

- *For all resources other than internal intermittent resources, ISO-NE requires that the amount of the capacity supply obligation be offered in both the Day Ahead and Real Time markets for every hour and every day of the capacity commitment period covered by the obligation.*
- *For internal intermittent resources, they have the option, but not obligation, of offering in the Day Ahead and must submit offers in the Real Time.*
- *Availability adjustments reduce FCM payments to a capacity supply resource based on the availability of the resource during "shortage events."*
- *Internal intermittent resources are not subject to availability penalties.*
- *Historically, using the definitions of Shortage Events, ISO-NE determined that there was a maximum of six events per year since 2000.*

1.7.1. Energy Market Offer Requirements

Capacity resources that acquire a supply obligation through any of the mechanisms described above have certain obligations in regards to offering their capacity in the energy market (Section 13.6.1 of the ISO Tariff). For all resources other than internal intermittent resources, there is a requirement that the amount of the capacity supply obligation be offered in both the Day Ahead and Real Time markets for every hour and every day of the capacity commitment period covered by the obligation. For internal intermittent resources, they have the option, but not obligation, of offering in the Day Ahead and must submit offers in the Real Time market. We discuss the detailed mechanics underlying these requirements in a later chapter.

1.7.2. Capacity Payments and Adjustments[30]

Except for intermittent resources, capacity resources that acquire a capacity supply obligation will be paid, on a monthly basis during the capacity commitment period, an amount equal to their capacity supply obligation times the capacity clearing price of the annual or reconfiguration auction or the bilateral price for the transaction in which the obligation was acquired.

Intermittent resources will be paid on the basis of their qualified capacity, with adjustments to this capacity level based on actual performance for subsequent years. After the first year of the capacity supply obligation, payments will be weighted 1/3 actual performance per year with the remainder based on qualified capacity levels. Thus after the third year, payments will be based entirely on actual performance during the winter and summer.

[30] This section is based on Section III.13.7.2 of the ISO Tariff.

These payments are subject to two types of adjustments: a peak energy rent (PER) adjustment and availability adjustments, both of which serve to reduce[31] the amount paid as described above. These adjustments are applied differently based on the capacity resource type. At a basic level, PER adjustments reduce capacity payments based on the difference between Real Time energy prices and a strike price, which is based on the incremental cost of a marginal proxy generating unit. All generating capacity resources, but not import capacity resources, will be subject to these adjustments.

Availability adjustments reduce payments based on the availability of the resource during "shortage events."[32] Shortage events usually feature the implementation of some capacity deficiency action or operating reserve shortage. However, internal intermittent resources are not subject to availability penalties. Availability during shortage events are tallied into monthly availability scores, and where there are no shortage events during that month, there will be no availability adjustments. A resource can be excluded from assuming a capacity supply obligation if it receives three annual availability scores of less than or equal to 40 percent and was unavailable in its entirety during ten or more shortage events during the most recent four years in which it assumed a capacity supply obligation. Once a resource is excluded it can only resume participation in the FCA if it receives availability scores of at least 60 percent in three consecutive years or capacity commitment periods or can show that the cause of poor availability has been resolved.

Historically, using the definitions of Shortage Events, ISO-NE determined that there was a maximum of six events per year since 2000. In a memo dated October 15, 2007, ISO-NE conducted an analysis looking at the New England system for the study period of January 2000 through September 2007.[33] The chart below represents the number of times a Shortage Event may have been called during the study period, if FCM rules for Shortage Events applied. It appears that six shortage events were the most shortage events for one year, with the highest frequency being three times in a single month. Overall, the number of shortage events per year appears to be less than seven.

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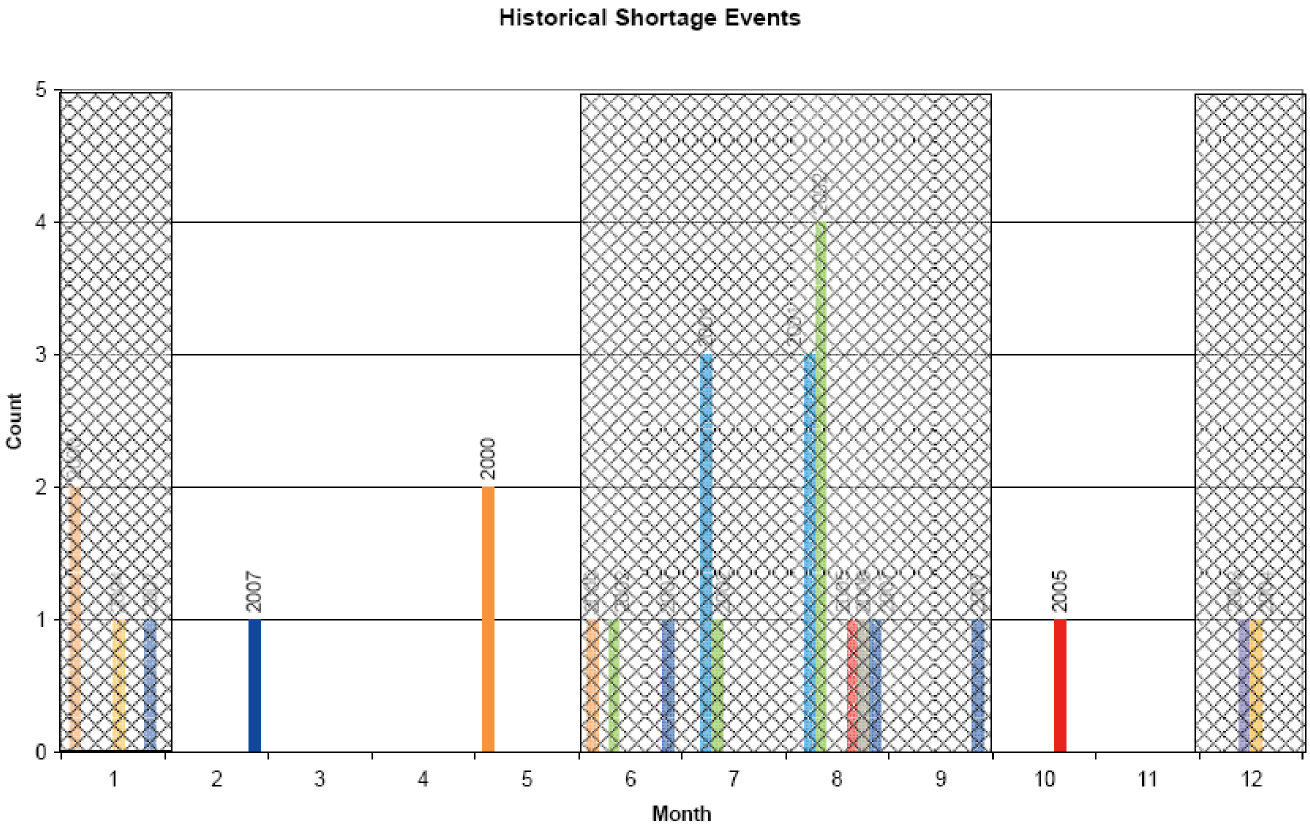
[31] Capacity that is fully available will receive availability credits as a result of the downward adjustments to payments due to unavailable resources.

[32] The exact definitions of a Shortage Event can be found in Section III.13.7.1.1.1 of the ISO Tariff.

[33] Power Supply Planning Committee, October 15, 2007 Memo on Historical Shortage Events.

http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2007/oct222007/pspc_memo_shortageevents_10222007pspc.pdf

Figure 4: ISO-NE Estimates of Historical Shortage Events



Source: ISO-NE Memo on Historical Shortage Event Frequency, dated October 15, 2007.

1.8. First Three Capacity Auctions

SECTION HIGHLIGHTS

- *The qualified existing capacity supply alone for FCA2 exceeds estimated future ICR levels until at least the 2016-2017 commitment period.*
- *Very few megawatts of new intermittent resources cleared in FCA1 and/or qualified for FCA2, supporting the notion that it may be too risky to commit new intermittent resources so far in advance of the delivery date.*
- *Only existing imports cleared in FCA1, while no new imports cleared the auction, though over 600 megawatts qualified.*
- *Import capacity resources are subject to rationing if interface limits are exceeded.*
- *For FCA2, a comparison of the total amount of qualified capacity to the net ICR level shows that there will likely be excess supply of capacity to meet the level of capacity needed, resulting in a clearing price equivalent to the floor.*
- *The tie benefits for specific interfaces for FCA2 changed significantly compared to FCA1.*
- *Any new entry into the capacity market will have little effect on capacity price levels over the foreseeable future.*

1.8.1. First Forward Capacity Auction (FCA1)

The first FCA (FCA1) was conducted in February 2008 and the results were reported by ISO-NE on March 3, 2008.[34] A total of 32,305 megawatts of capacity were procured by ISO for the first capacity commitment period, and a total of 34,077 megawatts cleared out of a possible 38,105 megawatts of capacity that qualified and participated in FCA1. Because supply exceeded demand, the clearing price was the floor price of $4.50/kW-month, and there was only one capacity zone.[35] All resources get a prorated portion of the total capacity revenues available, which is equal to Net ICR times the auction clearing price. Table 7 compares the megawatts that qualified to those that cleared, organized by capacity resource type.

Table 7: Megawatts of Qualified and Cleared Capacity in FCA1

	MW Qualified	MW Cleared
Existing		
Non-Intermittent Generation	29,786	29,183
Intermittent Generation	1,058	1,056
Demand Resources	941	1,366[36]
Imports	1,269	934
New		
Non-Intermittent Generation	3,720	616
Intermittent Generation	38	10
Demand Resources	2,490	1,188
Imports	658	0
Total	39,960	34,353[37]

Source: ISO-NE, La Capra Associates

The total megawatts of qualified capacity are net of accepted de-list bids. Exiting capacity resources must participate in all rounds of the auction but can opt out by submitting delist bids prior to the auction. In the first FCA, 389 MW of de-list bids were accepted by the ISO prior to the auction. During the auction, there were additional

[34] FERC Docket No. ER08-633-000.

[35] More MW than the amount procured were allowed to clear because of the existence of a floor price, which is in effect for the first three successful FCAs and for no more than the first five FCAs.

[36] The reason existing demand resources that cleared is higher than what qualified is that, for the first FCA, the market rules required new Real Time emergency generators to be treated as existing resources. In addition, new demand resources could elect existing resource treatment, so these resources may be included as "existing" as well.

[37] Includes 875 MW of emergency generation that cleared but were prorated down to 600 MW per capped levels found in the settlement agreement. The actual amount that was procured was 34,077 MW.

dynamic delist bids, which were allowed since prices fell below 0.8 times CONE—the floor price was 0.6 times CONE. These dynamic bids resulted in some existing MW leaving the auction and are reflected in the lower MW cleared figure for existing resources. Table 7 also shows only existing imports cleared, while no new imports cleared the auction, though over 600 megawatts qualified.

The table below is a summary of Massachusetts RPS-qualified renewable generators that also cleared in FCA1. These generators included intermittent and non-intermittent resources. Of those renewables that are Massachusetts RPS qualified, 60 MW of non-intermittent renewables cleared and 33.1 MW of existing intermittent and 10 MW of new intermittent cleared. Of note in Table 8 is the small amount of new intermittent resources qualifying and clearing in the FCA and thus anticipating commercial operation by June 1, 2010. This low number supports the notion that it may be too risky to commit renewable capacity (and thus have to meet all the requirements for capacity resources) this far in advance of the delivery date.

Table 8: Massachusetts RPS Qualified Renewables that Cleared in FCA1

Capacity Type	Existing/New	Cleared MW FCA 1
Non-Intermittent	Existing	60.4
	New	0.0
Intermittent	Existing	33.1
	New	10.0
Renewable Imports	Existing	0.0
	New	0.0

Source: ISO-NE, La Capra Associates

Table 9 shows additional detail for imports by interface, comparing what cleared to what actually will be eligible for capacity payments. Similar to the import rights during the transition period, transfer limits and tie benefits are used to determine the availability of the interfaces for delivering capacity. Import capacity resources are always subject to rationing if interface limits are binding (exceeded). This proration is in addition to the proration that occurred because the FCA1 price cleared at the floor.

Table 9: FCA1 Imports

Interface	Zone	Transfer Limit	Tie Benefits (for FCA1)	MW Qualified for FCA1	MW "Cleared" in FCA1	MW Paid in FCA1
NB-NE	Maine	1000	360	26	0	0
HQ Phase I/II	Rest-of-Pool	1400	1400[38]	942	268	0
Highgate	Rest-of-Pool	200	0	225	216	200
NY-NE AC	Rest-of-Pool	1525	100	734	734	734

Source: ISO-NE, La Capra Associates

As the table shows, there were 268 megawatts of supply that remained in the auction until the end (when the clearing price hit the floor price). These megawatts of capacity were prorated to zero since the HQ Phase I/II line had no availability (calculated as transfer limit minus tie benefits) to deliver capacity. Likewise, the Highgate interface was also oversubscribed by 16 MW and thus the total capacity over that interface had to be prorated from 216 to 200 megawatts.[39] No capacity cleared over the New Brunswick interface even though there was 640 megawatts of transfer capability available.

1.8.2. The Second Forward Capacity Auction (FCA2)

The second FCA (FCA2) is to be held on December 9, 2008. The ISO recently reported to the FERC the amount and list of resources that qualified for FCA2. In total, almost 43,000 MW were qualified for participation in the auction, compared to the net ICR value of 32,528 MW. A comparison of the total amount of qualified capacity to the net ICR level shows that, similar to the first FCA, there will likely be excess supply of capacity to meet the level of capacity needed. The existing capacity resources alone that are qualified for FCA2 is 35,479 MW, which is almost 3000 MW greater than the FCA2 net ICR level. As a result and assuming that existing capacity performs at the level at which they were qualified, the capacity clearing price will likely clear at or near the floor of $3.60 kW-month, resulting in capacity supply being pro-rated again. The major unknown is whether existing resources would delist because this price is too low.

[38] For the HQ Phase I/II line, the HQICC values are used rather than the tie benefit.

[39] March 3, 2008 ISO filing to FERC.

Table 10: Megawatts Qualified in FCA2

	MW Qualified
Existing	
Non-Intermittent Generation	30,361
Intermittent Generation	1,040
Demand Resources	2,767
Imports	1,311
New	
Non-Intermittent Generation	3,193
Intermittent Generation	106
Demand Resources	1,386
Imports	2,613
Total	42,777

Source: ISO-NE, La Capra Associates

For FCA2, there are more qualified new renewable resources than in FCA1. However, few new intermittent generators have qualified, supporting the discussion that few are willing to take the risk of participating in the FCM over three years in advance, despite favorable treatment of intermittent generators. Only one new non-intermittent Massachusetts RPS-qualified generator qualified for FCA2, though only a portion of its 120 MW capacity will be eligible since it will co-fire with biomass. There were over 50 MW of wind imports that qualified for FCA2.

Table 11: Massachusetts RPS Qualified Renewables that Qualified for FCA2

Capacity Type	Existing/New	Qualified MW FCA 2
Non-Intermittent	Existing	52.9
	New	120.8*
Intermittent	Existing	43.9
	New	7.7
Renewable Imports	Existing	0.0
	New	54.6

Source: ISO-NE, La Capra Associates

**Note: Somerset 6 plans to co-fire with biomass, so only a portion of the 120.8 MW would be RPS Qualified Renewable Generation.*

Table 12 shows the interface availability for FCA2. Though the transfer limits did not change at all and the total amount of tie benefits only fell 60 MW to 1800 MW, the tie benefits for specific interfaces changed significantly compared to FCA1. In particular, there was a big decrease in the HQ tie benefits and a large increase in the tie benefits from New Brunswick. As a result, there will be transfer capability made available on the HQ Phase I/II interface, which was fully subscribed in FCA1.

Table 12: Available Additional Import Capacity for FCA2

External Node	Zone	Transfer Limit	Tie Benefits (for FCA2)	MW Cleared in FCA1	Available for FCA2	Additional MW Qualified in FCA2
NB-NE	Maine	1000	716	0	284	300
HQ Phase I/II	Rest-of-Pool	1400	911	0	489	739
Highgate	Rest-of-Pool	200	0	200	0	25
NY-NE AC	Rest-of-Pool	1525	173	734	618	1871

Source: ISO-NE, La Capra Associates

The table also shows the megawatts of import capacity that cleared in FCA1 and calculates the additional availability on the lines for FCA2, assuming that the capacity resources that cleared in FCA1 also clear in FCA2, which may not be the case. Nevertheless, using this assumption, the table above compares availability over the various interfaces with the new capacity resources that qualified in FCA2, including those that qualified in FCA1 but did not clear. As shown, every interface have excess qualified capacity supply relative to its availability.

Table 13: Renewable Resources[40] and Imports in FCA1 and FCA2

Capacity Type	FCA 1 Status Existing/New	FCA 2 Status Existing/New	Resource Type	Generator Name	Qualified MW FCA 1	Cleared MW FCA 1	Qualified MW FCA 2	Qualified for MA RPS
Non-Intermittent	Existing	Existing	Biomass	INDECK JONESBORO	20.7	19.7	23.1	X
	Existing	Existing		INDECK WEST ENFIELD	22.2	22.2	23.2	X
	Existing	Existing		BORALEX STRATTON ENERGY	45.0	45.0	45.0	
	Existing	Existing		WARE COGEN - QF	0.0	0.0	0.0	X
	Existing	Existing		J C MCNEIL	52.0	52.0	52.0	
	Existing	Existing	Landfill Gas	JOHNSTON LANDFILL	12.0	12.0	0.0	X
	Existing	Existing		ROCHESTER LANDFILL	4.9	4.9	4.9	X
	New	Existing		COVANTA HAVERHILL LANDFILL GAS ENGINE	1.6	1.6	1.6	X
	New	Existing	Fuel Cells	DFC-ERG MILFORD	7.8	7.8	7.8	
	Existing	Existing	ROR Hydro	SANDY HOOK HYDRO	0.0	0.0	0.0	
	NA	Existing	Anaerobic Digestion	MONTAGNE FARM			0.1	X
	NA	New	Biomass	SOMERSET 6*			120.0	X
	NA	New	Landfill Gas	AMERESCO NORTHAMPTON			0.8	X
Intermittent	Existing	Existing	Biomass	BRIDGEWATER	15.4	15.4	15.4	
	Existing	Existing		GREENVILLE	13.7	13.7	13.6	X
	Existing	Existing		TAMWORTH	21.1	21.1	21.1	
	Existing	Existing		WHITEFIELD PWR AND LGT	13.6	13.6	14.0	
	Existing	Existing	Landfill Gas	FOUR HILLS LOAD REDUCER	0.3	0.3	0.3	
	Existing	Existing		TURNKEY LANDFILL	2.5	2.5	2.6	X
	Existing	Existing		DUNBARTON ROAD LANDFILL	0.7	0.7	0.6	X
	Existing	Existing		FOUR HILLS LANDFILL	0.7	0.7	0.5	
	Existing	Existing		PONTIAC ENERGY - QF	0.2	0.2	0.2	X
	Existing	Existing		ATTLEBORO LANDFILL	0.5	0.5	0.4	X
	Existing	Existing		MM LOWELL LANDFILL	0.3	0.3	0.3	
	Existing	NA		NEW MILFORD	1.6	1.6	NA	
	Existing	Existing		BARRE LANDFILL	0.5	0.5	0.6	
	Existing	Existing		CRRA HARTFORD LANDFILL	1.7	1.7	1.7	X
	Existing	Existing		RANDOLPH/BFG ELECTRIC	1.0	1.0	0.9	X
	Existing	Existing		GRANBY SANITARY LANDFILL	2.3	2.3	2.4	X
	Existing	Existing		PLAINVILLE GEN QF U5	4.7	4.7	4.6	X
	Existing	Existing		WESTFIELD #1 U5	0.1	0.1	0.1	X
	Existing	Existing		COVENTRY CLEAN ENERGY	3.7	3.7	3.2	X
	Existing	Existing		BRATTLEBORO LANDFILL	0.3	0.3	0.2	
	Existing	Existing		COVENTRY CLEAN ENERGY #4	1.2	1.2	1.3	X
	NA	Existing		MANCHESTER METHANE LLC EAST WINDSOR			1.4	X
	Existing	Existing	ROR Hydro	NEWPORT HYDRO	1.3	1.3	1.2	
	Existing	Existing		SWANS FALLS	0.2	0.2	0.2	
	Existing	Existing		CHINA MILLS DAM	0.0	0.0	0.0	
	Existing	Existing		PEPPERELL PAPER - QF	0.4	0.4	0.3	
	Existing	Existing		POINEER DAM HYDRO	0.0	0.0	0.0	
	Existing	Existing		NORTH HARTLAND HYDRO	3.5	3.5	2.7	
	Existing	Existing	Anaerobic Digestion	BLUE SPRUCE FARM U5	0.2	0.2	0.2	X
	Existing	Existing		BERKSHIRE COW POWER	0.3	0.3	0.4	X
	Existing	Existing		GREEN MOUNTAIN DAIRY	0.2	0.2	0.1	X
	Existing	Existing	Wind	SEARSBURG WIND	0.2	0.2	0.2	
	Existing	Existing		HULL WIND TURBINE U5	0.0	0.0	0.0	X
	Existing	Existing		HULL WIND TURBINE II	0.1	0.1	0.1	X
	Existing	Existing		PORTSMOUTH ABBEY WIND	0.0	0.0	0.0	
	New	Existing		SHEFFIELD WIND FARM	10.0	10.0	10.0	X
	Existing	Existing	Photovoltaic	BROCKTON BRIGHTFIELDS	0.0	0.0	0.1	X
	New	New	Wind	HOOSAC WIND	7.7	0.0	7.7	
	New	New		KIBBY WIND FARM	20.4	0.0	20.4	
	NA	New		PRINCETON WIND FARM PROJECT			0.7	X
	NA	New		BERKSHIRE WIND POWER PROJECT			2.6	X
	NA	New		LEMPSTER WIND			4.4	X
Renewable Imports	NA	New	Wind-New Brunswick	WEST CAPE WIND FARM			3.8	X
	NA	New		WEST CAPE WIND FARM #2			27.7	X
	NA	New		CARIBOU WIND PARK			23.1	
Other Imports	Existing	Existing	Other-New York	ERIE BOULEVARD HYDROPOWER	641.0	641.0	641.0	
	Existing	Existing		NYPA - CMR	78.6	78.6	79.9	
	Existing	Existing		NYPA - VT	13.9	13.9	17.8	
	Existing	Existing	Other-Highgate	VJO-HIGHGATE	225.0	200.0	225.0	
	Existing	Existing	Other-Hydro Quebec	LIEVRE RIVER PROJECT	200.0	0.0	237.0	
	Existing	Existing		VJO-PHASE I/II	110.0	0.0	110.0	
	NA	New	Other-New York	BEMI ONTARIO ASSETS			821.5	
	NA	New		CONSTELLATION ENERGY NEW YORK IMPORT			925.0	
	NA	New		HYDRO-QUEBEC CONTROL AREA-NEW YORK			120.0	
	New	New	Other-Hydro Quebec	HYDRO QUEBEC CONTROL AREA - HYDRO QUEBEC	631.8	0.0	391.9	
	New	New	Other-New Brunswick	HYDRO QUEBEC CONTROL AREA - NEW BRUNSWICK	26.0	0.0	300.0	

*Note: Somerset 6 is cofiring with biomass; total MW listed is not entirely RPS Qualified.

40 Includes only renewable generators that have qualified for one or more of New England states' RPS programs.

Source: ISO-NE, La Capra Associates

1.8.3. Third Forward Capacity Auction (FCA3) and Beyond

Looking beyond FCA2, the level of existing resources that qualified for FCA2 alone (assuming that the level of existing resources remains constant) will be greater than the net ICR level in future FCAs, at least through the 2016–2017 capacity commitment period (or FCA7).[41] Consequently, any new entry into the capacity market (or an imposition of a new capacity requirement as required by the Act) will have little effect on reliability levels. Also, assuming that existing capacity resources are at a cost advantage in terms of capacity revenue requirements (and thus would be able to offer capacity at lower prices) compared to new capacity resources, it appears that entry from new capacity resources will have little effect on capacity price levels as well. However, if the new capacity resources are renewable generators that are able to offer very low prices, or even become price takers, there may be some ability to suppress capacity prices, but only starting with FCA4, where there is no floor. The potential for price suppression is discussed in the next section.

There are a few caveats that may reduce the amount of existing capacity that participates in future FCAs:

- If there is a wave of retirements as older, existing generating resources reach the end of their useful lives and face cost pressures, such as emissions-related costs;
- If certain resources, notably demand response and other demand side resources are unable to meet the increased demands on their availability under the FCM (compared to the demand response programs prior to the start of the FCM); or
- If the auctions continue to result in low clearing prices, more existing capacity resources may de-list and/or sell to neighboring control areas.[42]

On the other hand, there could be factors that further exacerbate the capacity excess supply situation, such as expansion of energy efficiency spending and programs and standards and codes in the New England states, which would serve to both increase the supply of capacity and reduce the net ICR level. These factors would further reduce the capacity-market benefits of imposing a capacity requirement on RPS-eligible units.

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[41] This calculation assumes a compounded annual growth rate of 1.175 in the net ICR level.

[42] For example, CONE for FCA3 will likely be lower than FCA2, about $5.00/kW-month, resulting in a clearing price at the floor of about $3.00 per kw-month. Furthermore, with no floor prices for FCA4 and beyond, assuming FCA2 and FCA3 are successful, prices may drop even lower.

1.8.4. Discussion of Market Impacts of Increased Capacity

The argument that requiring renewable resources to supply capacity will increase the supply of low cost capacity in the Forward Capacity Auction and thereby drive down the clearing price is highly dependent on market conditions. Further research and analysis is required before it is reasonable to justify implementation of Section 105(c) with this argument.

First, whether or not the capacity clearing price is suppressed depends on the amount of incremental capacity needs and the behavior of the other Forward Capacity Auction participants. Intermittent resources get a small capacity rating due to the fact that it is difficult to predict whether or not the resource will be generating at the time of system peak. The Forward Capacity Auction is designed using a clearing price mechanism such that the last (highest priced) megawatt purchased sets the price for all other megawatts purchased. Under this market design, in order for a low cost renewable resource to affect the auction clearing price it would need to cause the most expensive megawatt to be displaced. Depending on the amount of low cost renewable resources participating in the FCA and the size of the most expensive block of capacity, the auction clearing price may or may not be affected. For example, if 20 megawatts of low cost renewable resources participate in the FCA, this would cause the 20 most expensive megawatts to be displaced. However if the price of the 50 most expensive megawatts were the same there would be no change in the FCA clearing price. A larger amount of low cost renewable resources participating in the FCA will have a greater likelihood of affecting the clearing price but that is not a deterministic outcome, especially over the long term when the stock of installed capacity in New England can change.

Secondly, by increasing the quantity of intermittent resources required to offer into the Day Ahead Market there is the possibility that other system costs, namely the cost to provide reserves, could increase. When ISO-NE plans the dispatch for the Operating Day, the cleared Day Ahead resources including imports are used as the basis for the Real Time dispatch. ISO-NE expects those resources that cleared the Day Ahead Market to be available in Real Time. To protect the system from resources which cleared Day Ahead but are unable to generate in Real Time, ISO New England maintains Operating Reserves.[43] Should ISO New England begin to observe a higher occurrence of or greater amount of intermittent resources that cleared Day Ahead but are not generating in Real Time it will need to increase the quantity of Operating Reserves it maintains. This issue of the effect of intermittent resources on operating costs is something ISO New England is presently studying.

[43] Operating Reserves are typically resources that can go from an offline state to online and generating in a very short period of time. While they can start quickly they tend to be very expensive to operate for any length of time.

I – 2 Energy Markets

As was mentioned earlier, a requirement of all resources supplying capacity to New England is that the resource must submit an offer into the Day Ahead and Real Time Energy Markets every hour in a quantity at least equal to its capacity obligation.

The Day Ahead and Real Time Energy Markets are designed to meet the region's energy needs. These markets are open to all **Market Participants** wishing to transact energy. The Day Ahead Market is a purely financial market which allows Market Participants to lock in a price for energy a day prior to when it is needed. This reduces the risk of prices moving unexpectedly due to an unforeseen event such as a generator outage or unusually hot or cold weather. The Real Time market is when energy is delivered.

In New England, the vast majority of load is served in the Day Ahead Market. Market Participants submitting bids and offers into the Day Ahead Market do not need to own generation or have a load obligation. Market Participants that do not have generation or a load obligation are able to enter what are called "Virtual Offers" or "Virtual Bids." Virtual Bids or Offers allow a Market Participant to assume or offset a position. They also allow arbitrage between Day Ahead and Real Time markets, which increases liquidity to the market, enhances efficiency, and causes prices to converge.

ISO-NE Market Participants

Resources wishing to participate in ISO New England markets must register as a market participant or enlist an existing Market Participant to serve as its agent in ISO-NE.

Registering as a Market Participant involves providing ISO-NE with business contact information such as a billing contact and scheduling contact. Market Participants must also list all their affiliated and related parties (see Appendix). In addition, Market Participants are required to maintain an account with ISO-NE for the purposes of posting financial assurance or collateral.

Entities that are approved as Market Participants receive access to the markets through ISO-NE's web based market interface. Market Participants wishing to import energy will do so through the Enhanced Energy Scheduler (EES) which is the module of the market interface that manages imports and exports.

The Real Time Market occurs during the operating day and prices reflect the actual dispatch of the electric system. Intermittent resources within New England and resources that are not participating in the Capacity Market can bypass the Day Ahead Market and offer their energy directly into the Real Time Market. This is the method that a majority of external renewable resources are using to sell energy into New England currently. One reason for this behavior is that energy can be self-scheduled[44] into the Real Time Market

[44] A self-schedule offer is essentially an offer at a zero price. With a self-schedule offer, the resource is willing to accept any clearing price. Self schedules may be submitted up to sixty minutes prior to the Operating Hour. This means that those submitting zero cost bids have up to sixty minutes prior to generating to let ISO-NE know how much output they are expecting.

up to 60 minutes prior to the start of the Operating Hour. This is beneficial for intermittent resources, especially wind, where the predictability of output is more difficult to forecast the further away from the Operating Hour the forecast is performed.

If these generators had cleared Day Ahead and then deviated from their schedule during Real Time, they risk having to buy the make-up energy in the Real Time market, which may be higher or lower than the price they were paid in the Day Ahead Market. Additionally, any deviations of volume (plus or minus) will be assessed a Net Commitment Period Compensation (NCPC)[45] charge based on the magnitude of the deviation on a daily basis.

2.1. Day Ahead Energy Market

SECTION HIGHLIGHTS

- *The Day Ahead Market is a purely financial market and there are no physical transfers of power.*
- *External resources submitting offers into the Day Ahead Market submit a virtual offer, which is an offer to sell at an external node at a price.*
- *Day Ahead purchases and sales of energy at an interface can result in net interchanges greater than its physical transfer limit. Furthermore, there are transactions occurring in both directions (purchasing and selling) simultaneously in most hours that may also exceed the transfer limit in either direction.*

Offers for the Day Ahead Energy Market are due by noon of the day prior to the Operating Day. There are two basic types of offers that a resource may submit, a self schedule or a price sensitive offer.

- A **self schedule offer** is essentially an offer at a zero price. With a self-schedule offer, the resource is willing to accept the Day Ahead clearing price, whatever it may be.
- With a **price sensitive offer**, the resource is only willing to participate in the Day Ahead Market if the clearing price is at or above the resource's offer.

As was mentioned earlier, the Day Ahead Market is a purely **financial market.** There are no transfers of power in the Day Ahead Market. In fact, Market Participants are not required to own generation or serve a load obligation to participate in the Day Ahead Market.

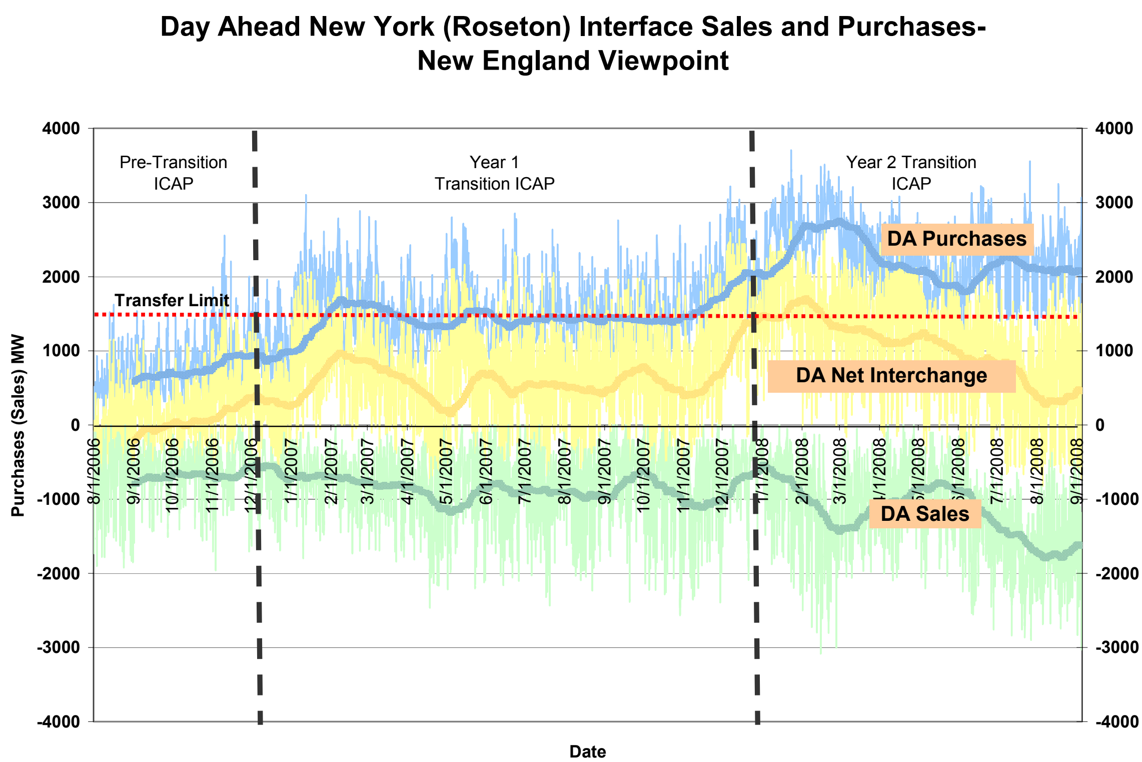
External resources submitting offers into the Day Ahead Market submit a **virtual offer**, which is an offer to sell at an external node at a price. Again, this is a purely financial transaction as the actual import of energy does not occur until Real Time. Once the Day

[45] NCPC are costs for maintaining the adequacy and security of the system which includes out-of-merit commitment costs, VAR support, and operating reserve costs. The daily total NCPC is divided by the total MWh of deviations across the entire system to derive a daily $/MWh charge to all deviations.

Ahead Market closes it is "cleared" by matching offers to sell against bids to buy and finding the price at which the two are the same.

The graph below, showing the Day Ahead purchases and sales of energy at the external node between New York and New England, demonstrates the "virtual" nature of a financial market in that the "net interchange" for New England can be greater than its physical transfer limit from day-to-day. Furthermore, there are transactions occurring in both directions (purchasing and selling) simultaneously in most hours.

Figure 5: Day Ahead Interchange



2.2. Real Time Energy Market

SECTION HIGHLIGHTS

- *When the FCM begins (mid-2010), those offers that cleared in the Day Ahead market are automatically self scheduled into the Real Time Market.*
- *Any deviations from the Day Ahead schedule in the Real Time will cause the Market Participant to incur a Net Commitment Period Compensation (NCPC) charge for the total amount of the deviation.*
- *Those submitting zero cost bids (self schedule in Real Time only) have up to sixty minutes prior to generating to let ISO-NE know how much output they are expecting.*
- *Intermittent generation will often self schedule in Real Time only, in order to ensure a match of delivery to actual output.*
- *Historical interchange data shows that, even though the Day Ahead market resulted in an expectation that a certain amount of energy will flow into New England (mainly to meet ICAP commitments), the Real Time market tends to offset that import amount by exporting energy when it is economic. This means even if there were increased imports to New England, the market may export a similar amount or more if economic to do so.*

At 4:00 pm prior to the Operating Day, the results of the Day Ahead Market are posted which includes the Day Ahead Location Marginal Price (LMP) and Day Ahead Obligations, all of which are binding but settled financially. From 4:00 pm to 6:00 pm the Re-offer Period occurs in which Market Participants can revise their offers for real time dispatch. It is also at this time that resources only participating in the Real Time Market submit their offers.

Again, offers for the Real Time market can be a self schedule, price sensitive, or a combination of both.

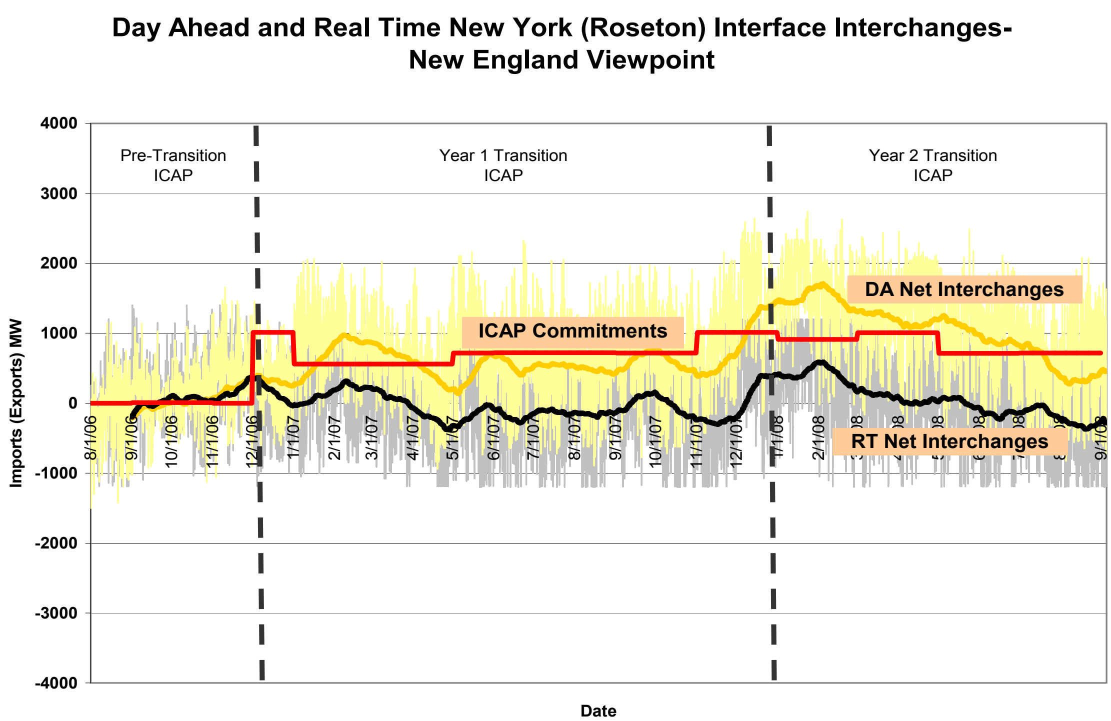
- When the FCM begins (mid-2010), those offers that cleared in the Day Ahead market are automatically **self scheduled** into the Real Time Market. Any deviations from the Day Ahead schedule in the Real Time will cause the Market Participant to incur a Net Commitment Period Compensation (NCPC) charge for the total amount of the deviation.
- Resources submitting **price sensitive** bids must do so during the Re-offer Period. Additionally, up to sixty minutes prior to the Operating Hour, these price sensitive bids may also be changed in terms of the offer price, but the megawatt quantity cannot be adjusted, except to zero.
- **Self schedules** may be submitted up to sixty minutes prior to the Operating Hour. This means that those submitting zero cost bids have up to sixty minutes prior to generating to let ISO-NE know how much output they are expecting. Intermittent generation will often take this avenue in order to ensure a match of delivery to actual output.

Individual Market Participants may make these changes and adjustments for a variety of reasons. However, the market as a whole, comprised of hundreds of different market participants and transactions, theoretically strives for the best economic outcome, where less expensive energy in one area will be moved to serve another area where energy is more valuable until some sort of equilibrium is obtained.

The requirement that external renewable generators must deliver their renewable energy into New England to be eligible for the Massachusetts RPS and the requirement that import capacity resources must offer their energy in the Day Ahead and Real Time markets, are exceptions to achieving the best economic outcome, since these resources must deliver energy to New England regardless of whether New England is a higher cost region.

The graph below, showing the Real Time net interchange at the interface between New York and New England, demonstrates this "corrective" or "equalizing" behavior of market participants in Real Time. This historical interchange data shows that, even though the Day Ahead market resulted in an expectation that a certain amount of energy will flow into New England (mainly to meet ICAP commitments), the Real Time market tends to offset that import amount by exporting energy when it is economic. This results in less net flow on average into New England in Real Time. This is key to understanding why the market overall may be importing and exporting energy simultaneously.

Figure 6: Day Ahead and Real Time Net Interchange



2.3. Additional Processes for Imports and Exports

2.3.1. NERC eTag Registration.

Import and export transactions must be accompanied by a valid NERC eTag. An eTag is used to track transfers of energy between control areas. Prior to submitting a request for an eTag, the entity wishing to transfer energy must register with NERC. The registration includes information such as business entity name and contact information and contact information for someone responsible for scheduling the energy transfers.

Once an entity has registered with NERC, a request for an eTag may be submitted for transactions. Details regarding the energy transfer are submitted including the size and duration of the transfer, when it is to take place, the source, destination and path of the transfer. The eTag may or may not contain information on the entity receiving the transfer. To the extent that an import is being sold into the Real Time Market the destination is just the system receiving the energy. Likewise, if an eTag is created to export energy, the destination is often just the system.

The eTag request is then sent to the control areas along the path of the transfer for approval. Once approved, the entity is eligible to transfer energy between control areas.

2.3.2. Transmission Reservations

In addition to a price and a quantity, a Real Time Offer must include a valid NERC eTag as well as a transmission reservation. Depending on the transmission facilities used in the import (i.e. the interfaces), an advanced transmission reservation may be required prior to submitting an import into the market system. [46]

Transmission reservations are not required for the Day Ahead Market because it is a financial only market and power does not physically flow. Market Participants are able to use both firm and non-firm transmission reservations when submitting import offers into the Real Time Market. Import offers are selected based on economic merit order with transmission priority used only as a tie breaker in the event that there are more megawatts of imports that are economic but insufficient transmission capacity to import all of the megawatts.

[46] For transfers from New York over the AC transmission facilities an advanced transmission is not needed. Transmission will be arranged in coordination with New York as part of the Real Time dispatch of the system. Transfers from Quebec and New Brunswick require advanced reservations because the transmission facilities utilized are not included as pool transmission facilities and therefore not paid for by the Regional Network Service rate.

From ISO-NE's perspective, in clearing the Real Time Market, it will continue to select all import transactions that have an offer price which is less than the locational marginal price (LMP) until there is no longer any available transmission capacity, regardless of the firmness of the transmission reservation. [47]

However, imports from Canada that have non-firm transmission reservations are at risk of being curtailed, or pro-rated down, if congestion is present on the transmission facilities used to import power from Canada.[48]

2.4. Day Ahead vs. Real Time Risk

SECTION HIGHLIGHTS

- *The ONLY time ISO-NE will impose a capacity market "availability" penalty against a resource is if that resource is not available, in part or in whole, during a "shortage" event.*
- *If a generator under-delivers during normal operations, the penalty is to buy make-up energy from the Real Time energy market at the delivery node.*
- *A Market Participant importing renewable energy into New England, if required to offer its capacity obligation into both the Day Ahead and Real Time energy markets, faces two main categories of risk: (1) volumetric risk and (2) Day Ahead to Real Time basis risk.*
- *A quantitative analysis of the potential impact on net revenues if an external intermittent generator were to schedule Day Ahead rather than only in the Real Time market shows that the impact would not average more than one dollar per megawatt-hour of delivered renewable energy.*

In order for an external resource to meet its capacity obligation it must offer into the Day Ahead Market. For external resources that can control their output this is not a problem. Intermittent resources, however, may not be able to deliver the quantity in Real Time that was cleared in the Day Ahead Market and face risks arising from the economic consequences of the under-delivery. As a result of these perceived risks, many external intermittent generators have chosen to forgo capacity revenues and sell energy only into the Real Time Market.

The consequence of implementing Section 105(c) of the Act is that all external intermittent generators would be required to offer some portion of their output into the Day Ahead Market. The quantity of output that would be required to be offered into the

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[47] ISO-NE will only look at firm and non-transmission rights if there is a tie between two offers.

[48] Market Participants that offer into and clear in the Day Ahead Market are subject to additional charges as a result of the import being curtailed. The Market Participant would be required to replace the curtailed energy at the Real Time LMP at the delivery node. In addition, the Market Participant would be assessed a Net Commitment Period Compensation Charge based on any deviation between the Day Ahead quantity and the actual delivered quantity.

Day Ahead Market is not specified in the Act.[49] It is unclear what the effect on the risk profile or costs will be to Market Participants with imports from intermittent generators. In interviews with Market Participants that currently are importing energy from intermittent resources, they have identified these perceived risks as impediments to the feasibility of Section 105(c).

2.4.1. Capacity Obligation and Energy Market Requirements

It is important to clarify some key misconceptions of how a resource's capacity obligation is linked (or not linked) to its Day Ahead and Real Time energy delivery requirements.

1. A Market Participant with an import capacity obligation is required to "**offer"** an amount equal to its capacity obligation every hour in the Day Ahead and Real Time markets (but does not necessarily have to "**clear"**)

2. If the Market Participant's offer **"clears"** the Day Ahead, then it must be responsible for delivering the energy in Real Time. At this point, the Market Participant is paid the Day Ahead clearing price multiplied by its offer amount.

3. Any deviation from this commitment, the Market Participant must make-up or "pay" for any shortfall. There are a couple of options for the Market Participant to achieve this: (a) buy make-up energy in the Real Time market at the delivery node or (b) pay for "firming" service provided by an entity from the originating control area.

4. During regular operations, the Market Participant does **NOT** receive an availability penalty against its FCM capacity obligation for not delivering an amount equal to it capacity obligation.

5. **The ONLY** time ISO-NE will impose an **"availability"** penalty is if that capacity obligation is not available during a **"shortage"** event.

Therefore, while we will discuss the energy market risks and penalties associated with under-delivery below, there are no capacity-market penalties related to the **"availability"** for a resource when there is not a "shortage" event. It is important to understand that a resource is not penalized when the associated generating asset is not generating at the obligation level in normal daily operations. Its "availability" risk, from a capacity market perspective, is only during "shortage" events, which have been estimated to be up to six times a year historically.

2.4.2. Energy Market Risks

A Market Participant importing renewable energy into New England, if required to offer its capacity obligation into both the Day Ahead and Real Time energy markets, faces two main categories of risk: (1) volumetric risk and (2) Day Ahead to Real Time basis risk.

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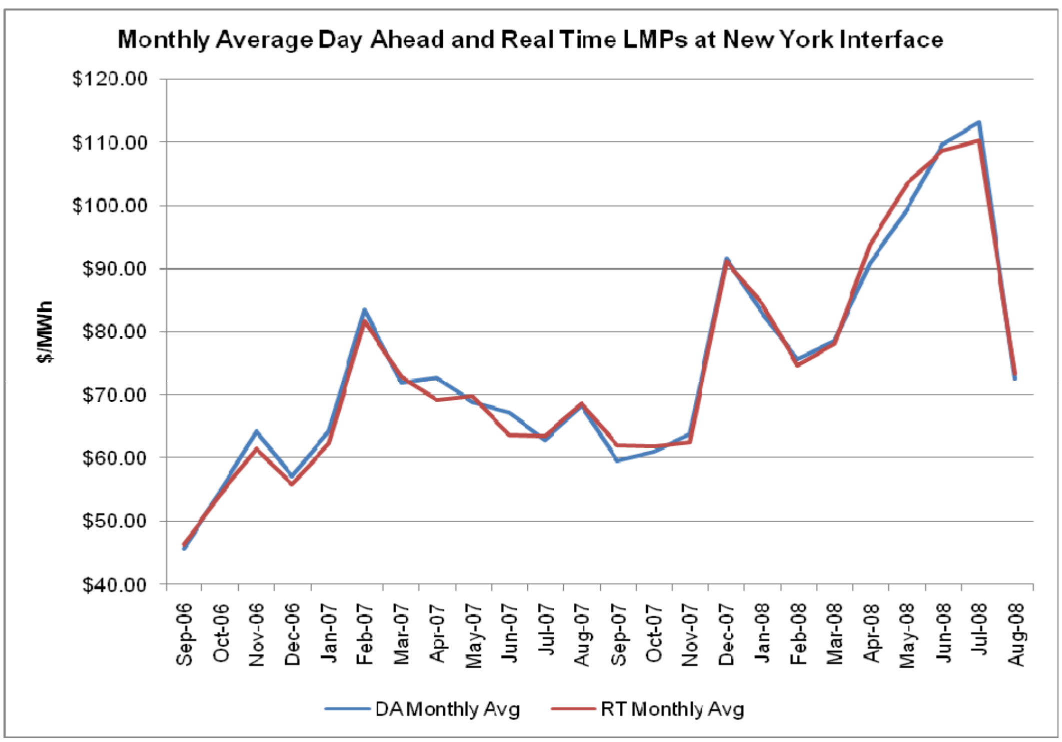
[49] This issue is also part of DOER's analysis and is presented elsewhere in the report.

(1) Volumetric Risk: If an intermittent generator commits to a Day Ahead schedule to meet its capacity obligation and ends up delivering below the schedule it would need to make-up that energy by procuring it in the Real Time Market. However, the intermittent can schedule any output above the capacity obligation separately in the Real Time market, thus removing the risk associated with over-delivery. This volumetric risk is increased by the fact that intermittent generators are likely to be curtailed, in whole or in part, during times when the transmission between its control area and New England is fully loaded. While this second aspect of volumetric risk exists today for external intermittent generators delivering energy into the Real Time market, it is not obligated to buy energy to make-up the shortfall relative to a Day Ahead schedule and is not subject to NCPC payments for deviating from a Day Ahead schedule.

(2) Day Ahead to Real Time Basis Risk: The second category of risk for external intermittent generators derives from the volatility/uncertainty of prices (Day Ahead, Real Time, and NCPC payments). The difference in prices for a given hour between the Day Ahead market and the Real Time market can be positive or negative and can vary dramatically. As described previously, offers that clear in the Day Ahead market are paid the Day Ahead price multiplied by the amount of the offer. However, in Real Time, if the generator is unable to deliver the full Day Ahead commitment it must make-up the shortfall by buying the energy from the Real Time market, regardless of the price. Historically, Day Ahead monthly average prices are more likely to be above Real Time prices than below for the same period, as seen in Figure 7 because there is a slight premium to have certainty of supply Day Ahead.

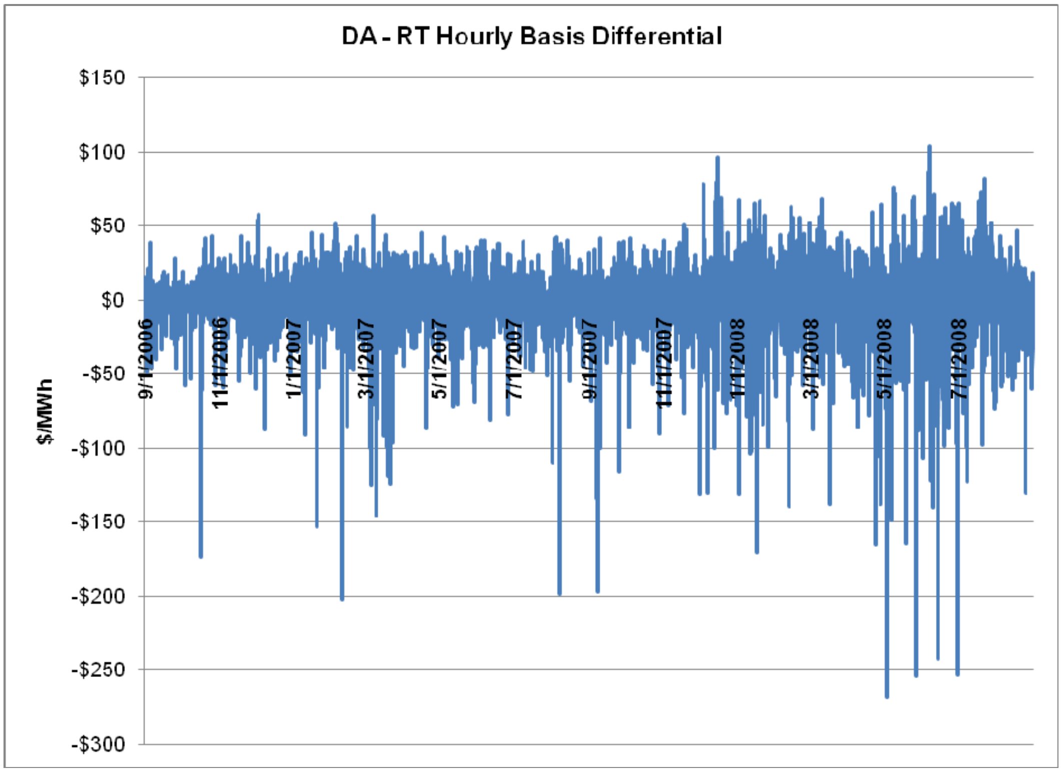
Figure 7: Historic Monthly Average Day Ahead and Real Time LMPs



Source: ISO-NE

However, there are some hours during which prices in the Real Time may spike to several hundred dollars per MWh above the Day Ahead price as can be seen in Figure 8 (a negative value indicates that the Day Ahead LMP was lower than the Real Time LMP). In these hours, if a generator cannot meet its obligation, it is subject to a very high price when making up its shortfall.

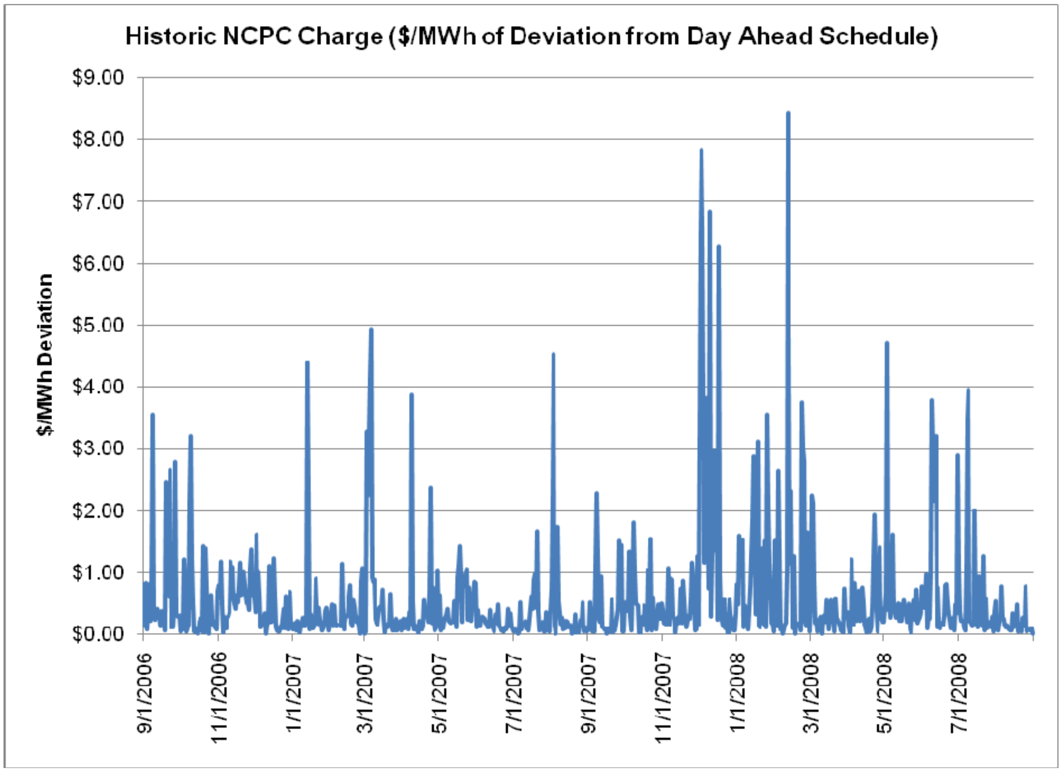
Figure 8: DA-RT Hourly Basis Differential



Source: ISO-NE

Furthermore, since NCPC charges vary daily depending on the total cost to the system of that day's deviations, generators are not able to precisely forecast what the cost of their deviation will be in the future. Over the last two years the average daily NCPC charge has been $0.58/MWh for deviations, though the charge can vary widely from day to day as seen in Figure 9.

Figure 9: Daily Historical NCPC Charge



Source: ISO-NE

2.4.3. Analysis of Risk

In order to understand the magnitude of these risks to external intermittent renewable generators, we developed an analysis using historical wind data to represent a proxy intermittent resource and two years of historical market data[50] for the Hydro Quebec, New Brunswick, and New York external nodes with New England.

The hourly output of the proxy unit is shown in the two figures below. The hourly wind patterns were derived from two-years of wind data[51] measured at Mt. Tom by the University of Massachusetts at Amherst and then we translated the wind data into hourly energy output.

50 The data include the hourly Day Ahead and Real Time LMPs at the Hydro Quebec, New Brunswick, and New York external nodes; the hourly net flows across the Hydro Quebec, New Brunswick, and New York interfaces; and the daily NCPC charges for the study period September 1, 2006 – August 31, 2008.

51 Where there were missing data, wind speeds for the same hours from previous years were used to fill in missing data.

Figure 10: Year 1 Hourly Output of Proxy External Intermittent Resource

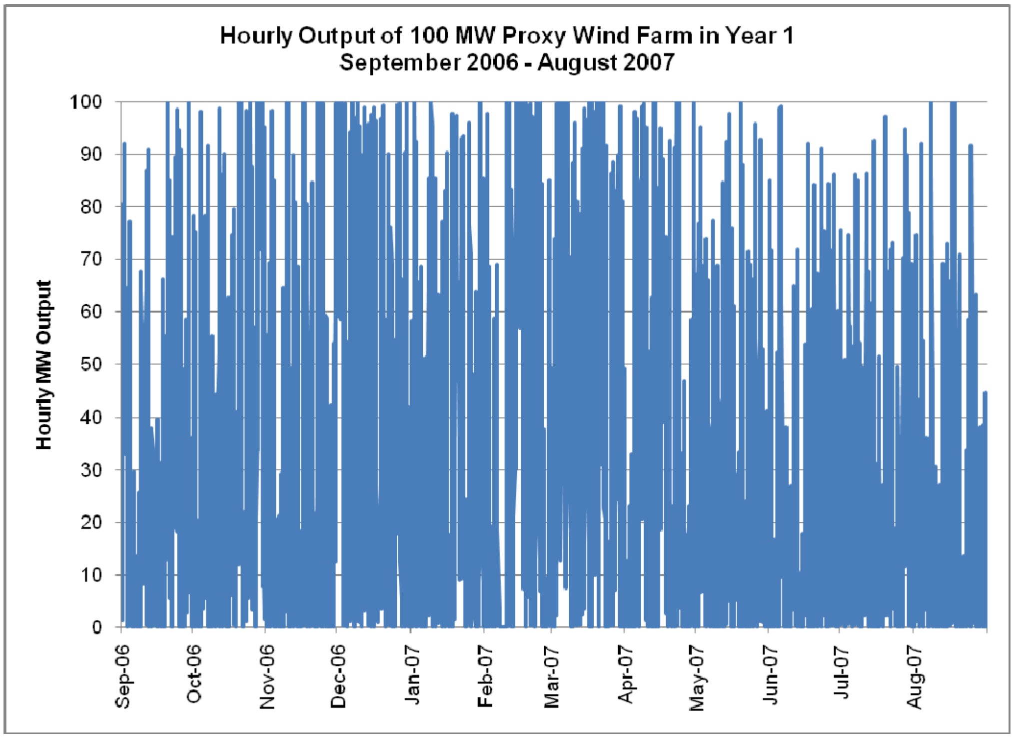
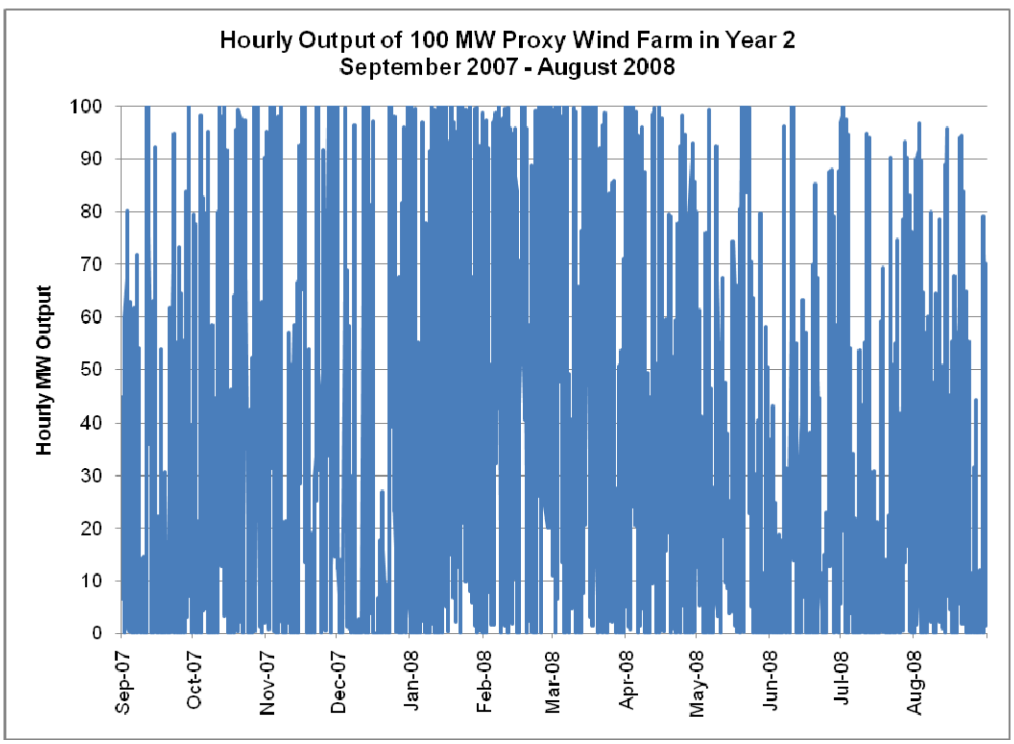
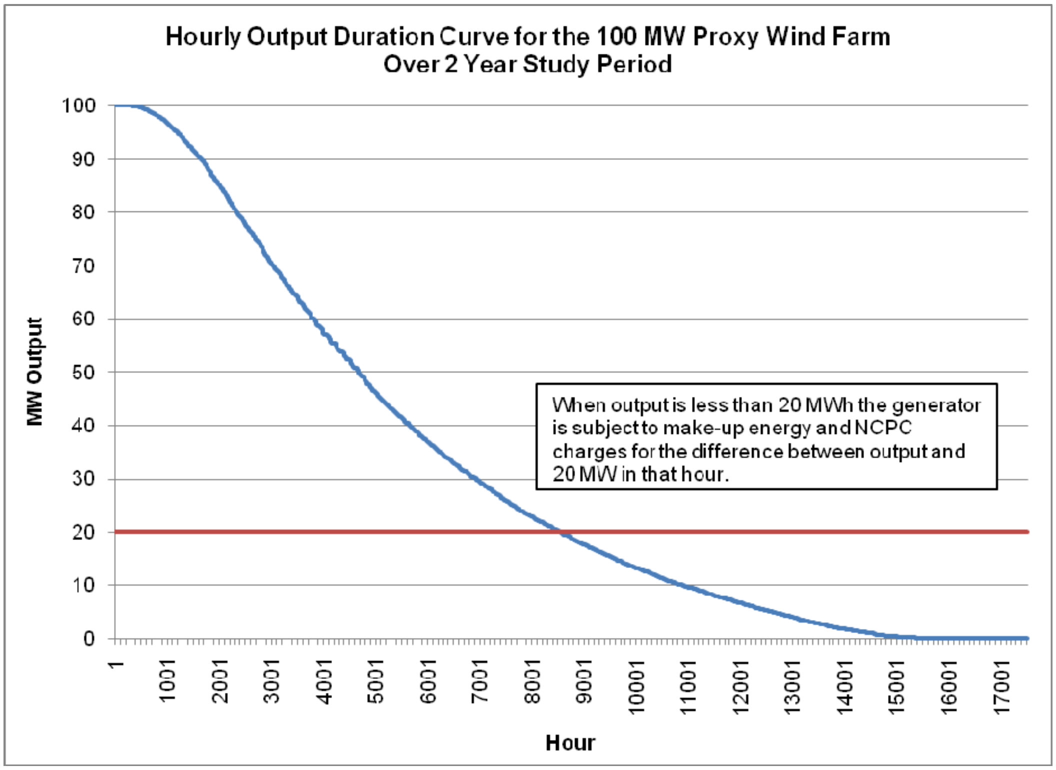


Figure 11: Year 2 Hourly Output of Proxy External Intermittent Resource



We assumed that a 100 megawatt wind facility would be able to provide only 20 megawatts of reliable capacity to the FCM. This means that the wind facility would offer (and clear) its 20 megawatts of capacity obligation in each hour, but the remaining output, above the 20 megawatts, can be scheduled into ISO-NE in Real Time, avoiding deviation risks. Any under-delivery of the 20 megawatts of capacity obligation would be subject to make-up Real Time energy penalties and any NCPC charges as described in the previous section. The generation duration curve of the proxy wind facility below shows that about 50% of the hours within a 2-year period would result in output less than 20 megawatts.

Figure 12: Hourly Output Duration Curve for 2 Years



The net revenues for each of the scenarios was compared to the net revenues under that scenario if all of the wind generator's output was scheduled in Real Time Only. This difference between each scenario and its Real Time Only counterpart provides the an estimate of the impact in scheduling Day Ahead in order to meet a resource's capacity obligation.

1. Reference: Day Ahead Scheduling for Capacity Obligation

- Assumes 20 MW are scheduled Day Ahead and are subject to NCPC charges and Real Time make-up energy costs for under-delivery
- Remainder of hourly output is scheduled in Real Time, but is subject to curtailments.[52]

[52] Curtailments due to transmission limitations are modeled using net imports as an indicator of these occurrences. Whenever net imports exceed a certain transfer limit (assumed HQ=1599 MW, New

2. **High Curtailment: Day Ahead Scheduling under High Curtailments**

- Assumes that the frequency of curtailments increase significantly, triggered in the model whenever the net interchange for imports exceed half of the interface limit.[53]

Table 14: Hours of Curtailment Simulated

	Reference	% of Total Hours Curtailed	High Curtailments	% of Total Hours Curtailed
Hydro Quebec	868	5%	10,486	60%
New Brunswick	101	1%	2,637	15%
New York	290	2%	2,791	16%

3. **High Curtailment Plus High NCPC:**

- Assumes High Curtailment scenario
- The historical NCPC charges are doubled

The net revenue under each of the scenarios above, if energy is scheduled only in the Real Time market, is calculated by multiplying the wind farm's hourly delivered energy (taking into account curtailments) with the hourly Real Time LMP at the delivery node. In the scenarios where Day Ahead scheduling is required to meet capacity obligations, the net revenues earned by external intermittent generators are comprised of the following components:

- **Day Ahead Revenue:** every hour the assumed 20 MW offer into the Day Ahead market is multiplied by the Day Ahead LMP.
- **Energy Cost to Make-Up for Under-Delivery in the Real Time:** in hours when the wind farm produces less than 20 MW, the shortfall is multiplied by the Real Time LMP to derive the cost of making-up that energy.
- **NCPC Cost for Under-Delivery in the Real Time:** the amount under-delivered due to underperformance or curtailments is multiplied by the NCPC charge for that day to derive the NCPC cost for the deviation from the Day Ahead schedule.

Brunswick=699MW, New York=1199MW), a curtailment of the full output for that hour is assumed to occur. These curtailments would occur regardless of whether the generator scheduled Day Ahead or Real Time.

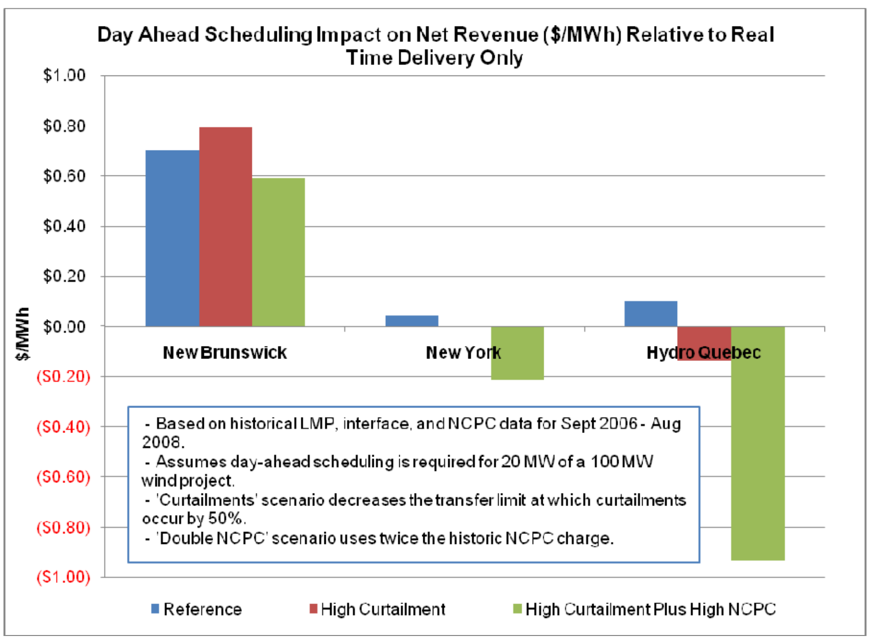
[53] This imitates a future where multiple wind projects may be competing for the same transmission, so curtailments would occur more frequently.

- **Real Time Revenue:** in hours when the project produces more than 20 MW, the incremental portion is scheduled into the Real Time market as a separate transaction. Thus, the revenue for this portion is derived by multiplying the incremental portion by the Real Time LMP.

The net revenue is the sum of these four components. Comparing the net revenues for each scenario provides an indication of the average impact of the Day Ahead Scheduling requirement on external intermittent generators relative to scheduling energy only in Real Time.

Figure 13 shows the impact on net revenues in dollars per megawatt-hour of delivered energy. Across the New Brunswick interface, all three scenarios show an increase in revenues because the Day Ahead LMP at the external node is often higher than the Real Time LMP. The impact along the New York interface is negligible. As for the HQ interface, the most significant impact on the net revenues of delivered energy occurs if there are curtailments during 60% of the hours within two years and the NCPC charges are double of historical levels.

Figure 13. Day Ahead Scheduling Impact on Net Revenue ($/MWh) Relative to Real Time Delivery Only



This analysis concludes that if an external intermittent generator were to schedule Day Ahead rather than only in the Real Time market, the impact on net revenues would not be on average more than one dollar per megawatthour even under the stressed conditions of high curtailments and high NCPC charges.

I – 3 NEPOOL GIS

The New England Power Pool Generation Information System (NEPOOL GIS or GIS) is a system that tracks the generation attributes of all energy on the ISO-NE system and is administered by APX, Inc. The system tracks the characteristics of every megawatt-hour of energy generated in, imported into, or exported[54] from New England. The data that are used to track all megawatt-hours come from the settlement data in the Real Time Energy Market and is provided by ISO-NE. While the NEPOOL GIS uses data primarily from ISO-NE, the tracking of attributes occurs separately from and after the market settlement. The NEPOOL GIS facilitates tracking of compliance with state regulations and reporting system attributes.

Every megawatt-hour of energy is issued a GIS certificate which describes attributes such as the fuel used to generate the energy and the emissions associated with that megawatt-hour. GIS certificates associated with energy from renewable generating units are commonly referred to as renewable energy certificates or RECs. A generation certificate becomes a Massachusetts REC when the generator is certified as an RPS-qualified renewable resource by DOER.

A function of the NEPOOL GIS is to keep track of which megawatt-hour megawatt-hours were generated by renewable resources and to whom the renewable energy was transferred for RPS compliance purposes. The NEPOOL GIS facilitates tracking and accounting of RECs for New England states as well as any transactions involving the sale of RECs between Market Participants, but does not serve as a clearinghouse for trades. RECs are used by DOER to monitor and enforce compliance of the RPS by Massachusetts load serving entities. In order to comply with the MA RPS requirement, a load serving entity must be able to show that it holds a sufficient amount of Renewable Energy Certificates.

3.1. Tracking of RECs of In-Region Renewable Generators

SECTION HIGHLIGHTS

- *The hourly generation of all internal generators is automatically captured by the settlement process and is recorded by the ISO-NE Asset ID.*
- *The source and amount of delivered internal renewable energy is recorded in the settlement data from ISO-NE and therefore is automatically verified.*

Internal renewable generators that participate in the ISO-NE market settlement system are identified by their ISO-NE Asset ID and by the ISO-NE Market Participant ID of their lead participant. These generators are considered NEPOOL generators[55] and are already

[54] Exports are considered “certificate obligations” and are treated as load, “Retail LSEs” for purposes of tracking attributes. Operating Rules 1/1/2008, 3.6

[55] New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 3.

registered in the NEPOOL GIS, Their generation characteristics automatically appear in the GIS Account of the Market Participant, "Account Holder," to which they are associated. The account holder updates the renewable generator's information in the NEPOOL GIS with the RPS eligibility status by state (entering the certification numbers for states in which the generator is eligible). The hourly generation of all internal generators is automatically captured by the settlement process and is recorded by their ISO-NE Asset ID.

During the quarterly 5-day long certificate creation period (see **Error! Reference source not found.**), the GIS administrator matches *every* MWh of generation to its GIS generator information,, creates certificates detailing the characteristics of *every* MWh of energy, and deposits the certificate into the respective Market Participant's GIS account.[56] These certificates automatically become Massachusetts Renewable Energy Certificates when the generator information for that Asset ID has received a Massachusetts state certification number, which is provided by the state once a project meets the state's RPS requirements. The source and amount of delivered renewable energy is recorded in the settlement data from ISO-NE and therefore is automatically verified. There are no additional steps for internal renewable generators to convert their generation certificates into RECs.

3.2. Tracking of RECs for External Renewable Generators

SECTION HIGHLIGHTS

- *External renewable generation must be tracked and verified in additional process steps, beyond just using settlement data.*
- *The external renewable generation is verified by actual metered data.*
- *ISO-NE does not verify whether the NERC tag itself has identified a generator as the source of the import, nor does ISO-NE verify whether the external renewable generator is actually linked to the energy scheduled into ISO-NE.*

In tracking renewable energy imports, ISO-NE can identify which control area imported energy comes from but cannot necessarily link it back to a specific renewable unit. Therefore, external renewable generation must be tracked and verified in additional process steps, beyond just using settlement data.

3.2.1. Registration in NEPOOL GIS

After the external renewable project is online and generating in its home control area, the account holder representing the external renewable generator[57] must register the

[56] New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 5-6.

[57] An external renewable generator could go through the registration steps, become a Market Participant, and represent itself in the ISO-NE markets and in the GIS certificate process. Or, what is more likely, the generator could contract with another entity that is already a Market Participant, a power marketer or the

generator with the GIS. Only ISO-NE Market Participants can be account holders with the GIS. Those that are not market participants are Non-NEPOOL account holders and are not allowed to register generators. The registration involves submitting information including the company name of the generator owner, generator asset ID in its home control area, location, and fuel source.[58] Furthermore, the agent must also identify its affiliates.[59] The agent must confirm the generator's RPS eligibility status for states using NEPOOL GIS tracked RECs, by providing the state certification number.[60]

3.2.2. Notation in ISO-NE EES as a Unit Contingent Transaction

When external generators or their agents schedule imports through the Enhanced Energy Scheduler (EES), they must make note that the import contract contains generation that will make unit contingent claims (that is, RPS eligible and wants to create RECs). They do this by checking the "Generation Information System" box in the Options screen of the EES scheduler and entering the "External Asset ID" into the Special Exception Comments box.[61] The "External Asset ID" consists of the initials of the home control (HQ, NB, or NY) area and the Asset ID assigned to the generator by its own control area (for example, NY12345).[62] By doing so, the GIS administrator will flag this as a unit contingent transaction when it receives the settlement data from ISO-NE.

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party ultimately buying the RECs, to be its agent through these processes. For the purposes of this explanation these options will be referred to collectively as the external renewable agent. The agent is meant to encompass the roles Market Participant and NEPOOL Participant Importing Account Holder.

58 Other required information includes multi-fuel capability, emissions rates and whether it is subject to emissions monitoring or reporting, labor characteristics, vintage, and capability to cogenerate steam and electric power. New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 8-9 and Appendix 2.4 p.3-4.

59 "For purposes of these GIS Operating Rules, two Account Holders are deemed to be affiliated Account Holders if: (i) one Account Holder owns, directly or indirectly, 10% or more of the voting stock or other equity interest in the other Account Holder; (ii) 10% or more of the voting stock or other equity interests in both Account Holders are owned, directly or indirectly, by the same person or entity; or (iii) one such Account Holder is a natural person, and such Account Holder or a member of such Account Holder's immediate family is an officer, director, partner, employee or representative of the other Account Holder." New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 8.

60 For Massachusetts this is also referred to as the RPS Statement of Qualification Number.

61 How to successfully register an import generator through the ISO-NE Enhanced Energy Scheduling (EES) system, and successfully claim the certificates through the APX GIS system," <http://www.nepoolgis.com/GeneralDoc/Import_Procedures_07-01-05.pdf>. and "User Guide for External Transactions using Enhanced Energy Scheduler – Tasks Section," <http://www.nepool.com/support/user_guides/external_transactions_using_EES.pdf>, p. 25.

62" How to successfully register an import generator through the ISO-NE Enhanced Energy Scheduling (EES) system, and successfully claim the certificates through the APX GIS system," <http://www.nepoolgis.com/GeneralDoc/Import_Procedures_07-01-05.pdf>.

3.2.3. Market Related Processes

After transactions are settled in the Real Time market, the ISO-NE adjusts each NERC eTag data to reflect the actual amount of imports or exports associated with the NERC eTag. However, ISO-NE does not verify whether the NERC tag itself has identified a generator as the source, nor does ISO-NE verify whether the scheduled energy was actually provided by the external asset or by system power.

ISO-NE transfers the settlement data to the GIS administrator electronically on a monthly basis. The key data that are transferred include: hourly settlement amounts by asset ID (if from an internal generator) or contract ID (if from an import contract); the NERC Tag ID (not the NERC tag itself) associated with import contracts; and the control area that imports are coming from. The import contracts which are flagged with an "External Asset ID" are posted in the Import Module in the online GIS software so that they can be claimed by their agent. During the certificate creation period the GIS administrator automatically creates certificates for all imported energy and these megawatt-hours are assigned the system characteristics of its originating control area[63] unless it is a contract that has been claimed (as described below) enabling the certificates to display unit specific characteristics.

Similar data are available for exported energy, though most exported energy are system energy and are not unit-specific, which means the exported energy has the New England system characteristics.

3.2.4. Agent Claims Contracts

For attributes associated with a specific "External Asset ID," the agent must log on to GIS within the allotted time period (**Error! Reference source not found.**) and claim the contracts associated with their "External Asset ID". The agent must additionally send the GIS: (1) attestation that the renewable attributes have not been otherwise sold or used for compliance in another jurisdiction and (2) the metered generation data[64] from the external renewable generator.[65]

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[63] New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 15.

[64] The metered data must meet the requirements of Operating Procedure No. 18. New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 4.

[65] New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 16.

Table 15: Timeline for GIS Process

Quarter of Generation	Import Claiming and Attribute Entry	Certificates Created	Trading Period
Q1 (Jan–Mar)	15-Jun–10-Jul	10-Jul–15-Jul	15-Jul–15-Sep
Q2 (Apr–Jun)	15-Sep–10-Oct	10-Oct–15-Oct	15-Oct–15-Dec
Q3 (Jul–Sep)	15-Dec–10-Jan	10-Jan–15-Jan	15-Jan–15-Mar
Q4 (Oct–Dec)	15-Mar–10-Apr	10-Apr–15-Apr	15-Apr–15-Jun

3.2.5. GIS Administrator Verifies Claims and Generates RECs

In order to ensure that RECs are only created for renewable energy that was delivered to ISO-NE, the GIS administrator: (1) verifies that the NERC tag ID associated with the import contract is valid, (2) compares the metered data to the energy associated with the contract on an hour by hour basis, and (3) creates RECs for the lesser of the two.[66] If there is any remaining energy associated with that import contract, the certificates for those MWh reflect the system characteristics.

Certificates are created and dispersed by the GIS administrator during the certificate creation period on a quarterly basis. Certificates can be retired, banked, or traded during the trading period that extends for two months after the certificate creation. The external generator agent has the 25 days period prior to certificate creation to claim its import contracts. Table 15 lays out the approximate time periods for the GIS process.[67] All load serving entities must procure certificates equal to the load that they served and must try to fulfill their RPS obligations by procuring the appropriate amount of the those certificates in the form of RECs.

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66 Interview with APX representative.

67 Interview with APX representative and New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 14-18.

Part II. Proposed RPS Requirements

II – 1 Section 105(c): Proposed Import Capacity Requirement

1.1. Implications of Proposed Requirement

Section 105(c) would require the "generator" of the renewable energy that is being delivered into New England from an adjacent control area to be a "committed capacity resource for the applicable annual period." Though the Act requires external renewable generators to be a "committed capacity resource," this term is not defined anywhere in the Act and not defined in the ISO Tariff. The ISO Tariff does define a "capacity supply obligation" and a "capacity commitment period."

If DOER determines that the Act would require external renewable generators to become a capacity supply obligation within the capacity market administered by ISO-NE, there are two major implications of such requirement.

1. An external renewable generator would need to take on a capacity supply obligation with ISO-NE for each annual capacity commitment period. To do so, the resource must first qualify for participation in the capacity market and then be able to obtain "import rights" during the transition period (until mid-2010) or "clear" in the annual forward capacity auctions or one of the reconfiguration auctions (after mid-2010).

2. As described in a prior section, capacity supply obligations are required to offer their capacity into the Day Ahead and Real Time Energy markets. If Section 105(c) requires participation in the FCM, it will alter the way many external renewable generators offer energy into New England. Presently, most external renewable generators schedule energy only in the Real Time market to reduce exposure to certain risks, but, going forward, offering into the Day Ahead may present additional risks.

It is important to point out that, by requiring external renewable generators to provide capacity, the Massachusetts RPS has expanded its focus from promoting green energy to also emphasizing capacity, which is needed for resource adequacy during peak hours and is a product separate from energy.

1.2. Technical Feasibility

It is technically possible to implement Section 105(c) by requiring external renewable generators to become capacity resources for ISO-NE under current market rules , though the opportunity to participate in the near-term capacity markets are limited and have significant uncertainties for generators. These are major impediments for generators to be able to participate in the near-term capacity markets, especially new projects. A delay to the start date of the capacity requirement until such time that all external renewable generators will have the opportunity to participate is warranted and should be considered.

- In the near-term, the present capacity procurement process for installed capacity (ICAP) during the pre-FCM transition period, has limited opportunities for external generators to obtain "import rights," largely because rights are granted based on the order in which applications are submitted. Since the start of the transition period, applications for import rights often exceeded the granted import rights, meaning that the number of import rights have been capped by the transfer limits. Thus, getting into the queue of applications of import rights does not necessarily guarantee the generator will be granted import rights.

  Additionally, the transition period ICAP does not provide an annual commitment as required by the Act, only seasonal commitments. External resources would need to commit for both summer and winter periods (by securing import rights for two consecutive months in each period) in order to assume a capacity commitment for the entire annual period, as required by the Act.

  More importantly, requiring renewable generators seeking Massachusetts RPS qualification to be committed during the transition period will not affect the price currently paid to capacity receiving ICAP payments, because capacity prices are based on a fixed-price schedule during the transition period. This requirement will also not impact reliability levels, because of the excess capacity—compared to installed capacity requirement (ICR) levels—that is already being procured.

- Since the Forward Capacity Auctions take place about three years before the capacity is required to be on-line and the qualification steps occur almost a year prior to the auction, the deadlines to participate in the first three auctions have passed. The first Forward Capacity Auction (FCA1) for the capacity obligation period of 2010/2011 occurred in February of 2008. ISO-NE already qualified all capacity for the second FCA (FCA2–2011/2012) in August 2008. The Statement of Interest (SOI) submission deadline for the third FCA (FCA3–2012/2013) has also passed.

- Newcomers or those that had not previously qualified for the FCM have some potential to participate in the reconfiguration auctions or through bilateral contracts. However, the availability of capacity obligations that will become available for external renewable generators to access through these secondary markets is extremely uncertain at this time. Factors that contribute to the uncertainty are:

  - The amount of obligations that will become available in the reconfiguration auctions or through bilateral contracts will largely depend on how many of the cleared resources with capacity obligations will want to shed these obligations due to, for example, not being able to meet their obligations in whole or in part. The key is that only those resources with capacity obligations can bid into the reconfigurations auctions or sign bilateral contracts. Furthermore, if the import capacity obligations are maxed out due to interface limits after FCA2 or FCA3, then external renewable generators would need to buy obligations from cleared import capacity obligations only, which is even more limiting. Load will not be able to buy capacity from resources through the auctions or through bilateral contracts.

- The reconfiguration auctions will also reflect changes in the ICR going forward, meaning that ISO-NE may adjust the ICR for a particular auction. If the ICR is adjusted downwards, similar to the slight drop in ICR for FCA1 to FCA2, less capacity will be needed.
- Lastly, the available import capacity at each interface is dependent on an interface's transfer capability minus the tie-line benefits. ISO-NE recalculates tie-line benefits each year which would impact the calculation of the available import capacity on the transmission lines. For example, the tie-line benefits over specific interfaces changed dramatically from FCA1 to FCA2.

Thus, should DOER determine to implement Section 105(c) in such a way where external renewable generators are required to participate in ISO-NE's capacity market, DOER needs to consider delaying the start of the requirement until the fourth FCA (2013/2014) at a minimum, when all external renewable generators will have the opportunity to participate. A delay will also allow existing contracts to be served without risking under-delivery in the next 4–5 years.

1.3. Practical Feasibility

While a generator can technically participate in the FCA—especially if the start is delayed until the fourth FCA (2013/2014)—DOER still must consider a number of issues with instituting a capacity requirement to determine if generators can practically comply and if benefits outweigh costs. DOER must also consider whether the regulations can be crafted to reasonably administer the requirement. Even if DOER delays the implementation of Section 105(c) until the fourth FCA, many of the uncertainties related to the size of available import capacity for each interface will continue to exist in subsequent auctions. Therefore, even if external generators bid zero prices and clear, there is no guarantee that a portion of their capacity supply obligation will not be pro-rated downwards, even to zero. This very real risk will impact these generators' ability to commit to multi-year contracts for financing purposes, which should be considered by DOER. This section discusses additional risks and their possible cost impacts to generators. We also highlight administrative issues that DOER will need to consider

1.3.1 Additional Risks Imposed on External Renewable Generators

If participation in the FCM is required, external renewable generators will be subject to multiple risks and uncertainties that may increase costs to the generator and/or hinder development, contracting, and their ability to get financing. Depending on the implementation details, DOER may be able to help mitigate some of those risks, especially with respect to the quantity of commitments required, the types of generators that must comply, and the timing of compliance.

Development Risk and Financial Assurance: For new projects under development, participating in the FCM means having to make a commitment over three years before a project comes on-line. This may prove to be difficult for developers with a portfolio of projects under development. New external resources that clear would need to provide financial assurances equal to the Cost of New Entry (CONE) multiplied by their "cleared" capacity obligation—not necessarily their "qualified" capacity—for each year leading up to the delivery date. All new capacity resources are subject to forfeiting their financial assurance if the new capacity resource is unable to deliver any portion of the capacity supply obligation. There are ways to reduce one's capacity supply obligation and thus reduce or eliminate this loss of financial assurance.[68]

To provide DOER with a sense of the magnitude of this risk for a developer, we consider an example of financial assurance, which could be a letter of credit, for a 100 megawatt wind farm that commits 20 megawatts in the capacity market. The total combined financial assurance of three years of CONE[69] is estimated to be $360,000 or equal to about $1.30–$1.50 per MWh of a single year's output.[70] Relative to the revenue potential for selling RECs to Massachusetts, this appears to be fairly minor. The level of assurance will be lower the less capacity is required to be committed for RPS eligibility.

At worst, projects concerned about development risk may have to forego Massachusetts RPS qualification and find alternative REC markets for the first few years of operation, in order to ensure that the project will be on-line to meet its capacity supply obligation.

Day Ahead Energy Market Risk: For an external resource to meet its capacity obligation, it must offer into the Day Ahead Market. This is not a problem for external resources that can control their output. Intermittent resources, however, risk not being able to deliver the quantity in Real Time that cleared in the Day Ahead Market and the economic consequences of the under-delivery. In The Day Ahead Energy market, there are two major risks for intermittent generators: (1) the difference in volume between Day Ahead vs. Real Time and (2) the difference in price between the Day Ahead vs. Real Time markets as discussed in Part I.

If an intermittent generator commits to a Day Ahead schedule to meet its capacity obligation and ends up delivering below the schedule, it would need to make-up that energy by procuring it in the Real Time Market. This volumetric risk is increased by the fact that external intermittent generators are likely to be curtailed, in whole or in part, during times when the transmission between their control area and New England is fully loaded.

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68 For example, if a project sponsor is unable to achieve commercial operation by the start of the capacity commitment period, he would be able to transfer his capacity supply obligation to another entity until his project is running. However, there are limits to how long the ISO will accept delays, since the ISO has the right to terminate a resource's capacity supply obligation and not return financial assurance in the event that the resource has not achieved commercial operation after two capacity commitment periods following the start of the capacity commitment period for which the resource assumed a capacity supply obligation.

69 CONE for the second FCA is $6/kw-month. We anticipate that CONE will be even lower for the third FCA.

70 Assuming capacity factors of 28% to 32%.

The second category of risk for external intermittent generators derives from the volatility and uncertainty of Day Ahead prices, Real Time prices, and NCPC payments. The difference in prices for a given hour between the Day Ahead market and the Real Time market can be positive or negative and can vary dramatically. As described previously, offers that clear in the Day Ahead market are paid the Day Ahead price multiplied by the amount of the offer. However, in Real Time, if the generator is unable to deliver the full commitment, it must make-up the shortfall by buying the energy from the Real Time market, regardless of the price, or find other avenues to secure the energy needed.[71]

Historically, Day Ahead monthly average prices are more likely to be above then below the Real Time prices for the same period because there is a slight premium to have certainty of supply through the Day Ahead Market. However, there are some hours during which prices in the Real Time may spike to several hundred dollars per MWh above the Day Ahead price. Generators who cannot meet their obligations during these hours pay a very high penalty to make-up the shortfall.

In Part I of this report, we estimated a range of potential impacts to the average net revenue per megawatt-hour (over two historical years) for external intermittent generators that must offer energy in the Day Ahead market. The analysis showed that an external wind project (100 MW) providing 20 MW of capacity obligation across each of the key interfaces—New York, Quebec, and New Brunswick—may experience an increase of almost $1 per MWh in revenues across the New Brunswick interface to a decrease of about $1 per MWh in revenues across the Quebec interface. The average impact to a wind generator does not appear to be substantial.

Availability Risk: External intermittent generators are also concerned about the capacity-market penalties for *not* being available during shortage events.

The maximum penalty for not being available for an external generator during shortage events is capped at the annual FCM payment for that generator. Thus, at worst, the generator forfeits its FCM payment for that year.

If the generator consistently underperforms (receives an availability score of less than 40% for three years and is completely unavailable for ten shortage events within a four year time frame),[72] then the generator is disqualified from being a capacity resource until such time it can demonstrate good performance. Depending on what DOER requires of intermittent generators, the capacity obligation may be minimal and may consider the issue of availability.

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[71] The Market Participant does NOT receive an availability penalty for not delivering an amount equal to it capacity obligation during daily operations if its asset is underperforming.. The ONLY time ISO-NE will impose an “availability” penalty is if that capacity obligation is not generating during a “shortage” event as defined in ISO tariff rules related to FCM.

[72] Section III.13.7.1.1.5 of the ISO Tariff

In summary, we believe that external intermittent generators should be able to manage the additional risks discussed in this section at a reasonable cost level, though there will be additional administrative costs associated with applying and qualifying for the FCM and scheduling Day Ahead. Additionally, especially given the current state of the financial markets, investors may account for these added risks by increasing the cost of financing or reducing the number of options available to generators for financing a project.

1.3.2 Disparate Treatment of External vs. Internal Resources

As the Act is currently written, implementing this requirement would result in uneven treatment of external intermittent generators versus internal intermittent generators. Even if the capacity requirement for RPS eligibility is modified through statute to apply to both internal and external generators, there is still disparate treatment of these two groups of generators under the ISO Tariff for the FCM. Table 16 illustrates some of these differences.

Table 16: Different Treatment of Internal and External Intermittent Resources in ISO Tariff

	Internal Intermittent	External Intermittent
Qualified Capacity	Based on claimed values by project sponsor Can change values during qualification process	Qualified capacity values cannot be changed during the qualification process Imports are not distinguished by generator types (intermittent or non-intermittent) in determining qualified capacity levels
Capacity Commitment Period	New resources can opt for a five-year commitment period for capacity supply obligations	New Resources can only receive one-year capacity obligations
Market obligation	Must offer entire capacity obligation only in Real Time energy markets	Must offer entire capacity supply obligation in both Day Ahead and Real Time energy markets
Availability penalty	No availability penalties	Availability penalties based on performance during shortage hours Can be excluded from future capacity commitment periods for consistent underperformance

Within the FCM, the greatest differences in treatment of internal intermittent and external intermittent generators are: (1) import resources are not distinguished between intermittent and non-intermittent; (2) internal intermittent generators do not have to submit offers in the Day Ahead market and (3) internal intermittent generators are not subject to any availability penalties.[73]

The first major difference presents an issue for DOER because DOER will need to determine what would be a reasonable and feasible amount of capacity to require from external intermittent resources since they are not able to provide reliable capacity at a level similar to their nameplate rating. Related to that, DOER would need to determine to what extent the amount of capacity commitment should be tied to the number of RECs that can qualify, since RECs are based on energy output, not capacity.

1.3.3 Costs and Benefits

In addition to the costs and risks faced by generators, DOER will need additional staff to verify capacity commitments during the RPS qualification process. ISO-NE is looking only to make sure an import capacity resource will be able to meet its proposed capacity supply obligation at a minimum.[74] For example, if a 100 megawatt wind generator submits a capacity supply offer of 1 megawatt, ISO-NE will likely approve the resource because it has provided sufficient documentation that proves it can meet the 1 megawatt commitment. However, the 1 megawatt of capacity is not necessarily the maximum capacity that a 100 megawatt wind farm can reliably supply. DOER will need to determine and verify the maximum capacity commitment that would be required of the generator for RPS eligibility.

Depending on how DOER structures the capacity obligation requirements, there may be some potential to suppress capacity prices, by introducing zero cost capacity into the FCM, without drastically limiting the amount of RECs that can qualify for the Massachusetts RPS. However, the price of RECs may be higher if new generators choose not to participate, causing a reduction in future supply, or the added costs for participating in the capacity market is included in the price of RECs.

Based on the current list of Massachusetts RPS qualified external renewable generators, Section 105(c) can potentially impact over 700 megawatts of external renewable generators that have already qualified for the RPS, eventually totaling 2,100-2,300 gigawatt-hours of RECs per year (see Table 17 below). This is equivalent to about 42%-47% of the Massachusetts 2014 RPS target (~4,860 gigawatt-hours). Since most of the qualified renewable energy projects are wind projects, the capacity commitment from these intermittent resources may be only 90 to 160 megawatts of the 625 megawatts of qualified wind projects. Even if future qualified renewable imports expand to double the amount of wind projects, the capacity commitment will be at most 320 megawatts. The remaining imports are landfill gas and biomass projects that may or may not be considered intermittent generators by DOER. Their capacity contribution total less than

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[73] Changes to these definitions for imports and intermittent generators are under consideration by ISO-NE.

[74] External generators can be backed by its own asset or a contract (with another capacity asset or a system operator).

100 megawatts. In total, requiring external renewable generators to commit capacity will not likely add enough capacity supply to the FCM to suppress prices significantly.

Table 17: Massachusetts Qualified Renewable Energy Generators[75]

	RPS Qualified (MW)	Estimated RECs		Estimated Capacity Commitment	
		Low (GWh)	High (GWh)	Low (MW)	High (MW)
Wind	625	1,532	1,642	94	156
Landfill Gas	74	485	582	55	66
Biomass	6	41	43	5	5
Total	704	2,058	2,267	154	228

1.4. Implementation Issues and Options

Having highlighted some issues associated with practical feasibility of the capacity obligation, we present some options that DOER would need to consider with respect to implementing Section 105(c).[76]

In summary, there are four key implementation issues that would need to be addressed by DOER in some manner if Section 105(c) is to be implemented.

- *When and to what extent should capacity commitment requirements apply to external generators in order to address the risks associated with the availability or accessibility of import capacity?*
- *What amount of capacity would be required of a "committed capacity resource" to qualify for the Massachusetts RPS and to what extent should the RECs that qualify for the Massachusetts RPS match to the capacity requirement, if at all?*
- *Should an import capacity supply obligation be required to be backed by a renewable energy asset?*
- *Should internal generators also have to commit their capacity on a comparable basis?*

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[75] DOER approved applications for statement of qualification for RPS-Qualified, New Renewable Generation Units as listed on www.mass.gov.

[76] In the discussions below, the requirements for a renewable generator are assumed to be tied to the portion or percent of the nameplate capacity of the generator intended to qualify in the Massachusetts RPS. For example, if an external resource has already contracted 40% of its output to a non-Massachusetts party and would like to qualify or has qualified the remaining 60% for the Massachusetts RPS, the requirement will apply only to this portion.

Issue I:

When and to what extent should capacity commitment requirements apply to external generators in order to address the risks associated with the availability or accessibility of import capacity??

Option 1: Apply Immediately (2009)

The opportunity is limited for external renewable generators to access import rights (certain interfaces are at their maximum for the transition period) during the transition period. Also, the transition period does not provide for an annual commitment period as currently proposed in the statute. While technically feasible for certain interfaces, it is not practically feasible for generators to comply with this option. .

Option 2: Apply at the Start of the Forward Capacity Market (2010/2011)

The FCA1 has cleared, the FCA2 deadline to qualify has ended, and the Statement of Interest (SOI) submission deadline for FCA3 has passed. Securing a capacity supply obligation will depend on the reconfiguration auctions and bilateral contracts with cleared obligations. The availability of import capacity obligations that external renewable generators can access through these secondary markets is extremely uncertain during the intermediate time period. As a result, it is likely unfeasible for all renewable generators to have an opportunity to become a committed capacity resource..

Option 3: Assess Situation After FCA3 Has Cleared

Wait for the auction results of FCA3 or the first reconfiguration auction to determine whether there is import capacity available for external generators for FCA4 (2013/2014). This might stall decisions to invest in generation (in neighboring control areas for purposes of delivering to New England) until the FCA3 auction is held in October of 2009. The results for the FCA3 auction are announced after the SOI submittal time for FCA4,[77] so external renewable generators would need to submit an SOI with a small financial deposit of $1,000 for imports to get qualified. Since import capacity resources get only one-year commitments, there still will be risks associated with the availability of import capacity on the interfaces from year to year and with being pro-rated downwards thereafter. These risks may prevent many renewable generators from participating.

Option 4: Start with FCA4 or Beyond, But Allow for Pro-rated Cleared Obligations

Require all imports to submit a SOI for FCA4, to qualify, and to stay in the auction—even if prices fall to zero.[78] Generators who cleared but were pro-rated downwards, even to zero, would not be penalized. Subsequent auctions would have these same rules.

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[77] FCA4 starts in June 2013, with SOIs due in mid-July of 2009.

[78] Resources that bid below 0.75 x CONE will trigger a review by the FCM Market Monitor and would need to provide justification for a low or zero price bid.

This approach would include allowing all output (or a designated portion) to qualify for the Massachusetts RPS as long as the resource "cleared" in the auction, regardless of the actual amount that cleared. This option alleviates the uncertainty of what transfer capability will be available for imports from year-to-year and risk of being pro-rated, while still motivates generators to participate in the capacity market to the extent they can. It also allows generators to meet the "letter of the law" without sacrificing the amount of RECs that can be eligible. This option might not provide incremental capacity benefits if import capacity that clears by FCA3 are at the import capacity maximums, but it will, at least, provide the potential for reducing prices if more capacity is required to be "price takers" in the FCM. By waiting until FCA4, there is no longer a price floor, so prices have the potential to fall to zero. By alleviating the uncertainties year-to-year for the level of commitment required, this option becomes more feasible.

Option 5: Meet Capacity Requirement Outside of the FCM

Since the Act does not define exactly what it means to be a "committed capacity resource," DOER has the discretion to define this term separate from acquiring a capacity supply obligation through the FCM. For example, this can mean that the external renewable generator commits to providing its entire (or portion of) actual output to New England, especially during shortage events. To ensure coincidence of its output with shortage events, it would be best if the renewable generator sends its output to New England in every hour during the Real Time Market, but not necessarily schedule Day Ahead. This option may also require the generator to de-list from its control area, if such a process exists. Overall, this option has the lowest risk for external renewable generators, since they would not be subject to the uncertainties of the FCM and they would not have to offer in the Day Ahead market. It can also be implemented almost immediately.

On the other hand,, this option will not contribute to more capacity participating in the ISO-NE capacity auctions and will not help to suppress capacity prices experienced by load in New England. Since there is no participation in the ISO-NE capacity market, ISO-NE will not be able to include these resources in its planning. Furthermore, if DOER requires generators to de-list from their home control area, no control area benefits from the capacity contribution of these generators, thus more capacity may need to be acquired by these home control areas for reliability purposes. Finally, DOER will need to establish rules around how to penalize external renewable generators if they do not meet a certain minimum level of availability during "shortage events." APX will need to set-up additional verification processes to check that the generation and delivery of the output occurred during shortage events. Overall, this is the lowest risk and lowest cost option for external renewable generators, but there will be no benefit to the capacity market and poses some administrative challenges.

Issue II:

What amount of capacity would be required of a "committed capacity resource" to qualify for the Massachusetts RPS and to what extent should the RECs that qualify for the Massachusetts RPS match the capacity requirement, if at all?

Option 1: Capacity Commitment Tied to Hourly REC Generation

Essentially, this option allows only RECs that are fully "capacity"-backed to qualify.

This would not be an attractive option for intermittent generators since they are more an energy resource than a capacity resource. Project owners might find increased risk if their capacity obligations were prorated downwards differently from year-to-year and, as a result, not be able to forecast the amount of RECs that can qualify and, ultimately, their potential revenue streams. Intermittent generators will be limited by the amount of RECs that can qualify for the Massachusetts RPS, causing the remainder of RECs to go to other markets. APX would need to conduct an additional verification and confirmation step of comparing a generator's output to its capacity obligation in creating RECs.

Overall, this option is not feasible since it is beyond what is authorized by statute. Based on legislative history, this option was consider and discarded.

Option 2: Same as ISO Rules for Internal Resources with Full REC Allowance

Under this option, the portion of the nameplate capacity required to be committed capacity for Massachusetts RPS eligibility would be based on applicable ISO FCM rules for determining qualified capacity of internal intermittent power resources, but all delivered output (or designated portions) would qualify for RECs. Intermittent generators (wind, ROR hydro, some LFG, some biomass) would need to commit up to their output equivalent to an internal intermittent resource in ISO-NE, which is equivalent to the median of output during certain winter and summer peak hours.[79] Non-intermittent generators (some biomass, some LFG) would need to commit their full (or a portion of capacity intended to meet Massachusetts RPS) Summer Claimed Capability (SCC) and Winter Claimed Capability (WCC).

DOER would need to verify the claimed capabilities, since ISO-NE only verifies that an import can meet its cleared capacity supply at a **minimum**, but not determine the generator's **maximum** capacity supply potential. All output (or a designated portion) can qualify as long as the generator commits some capacity (as determined by previous options on how much to commit) and continues to adhere to the hourly matching of the delivered energy requirement. This would allow external intermittent generators to

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79 Summer intermittent reliability hours are the four hours between 2 and 6 PM during June through September, and Winter hours are the two hours between 5 and 7 PM during October through May; all shortage-event hours outside of these periods are also included (Sections III.13.1.2.2.2.1(c) and III.13.1.2.2.2.2(c) of the ISO Tariff).

commit a similar amount of capacity as an internal intermittent generators commit, if it were required to provide capacity.

Option 3: Pre-set Minimum of Capacity with Full REC Allowance

For this option, external generators would need to commit a pre-set minimum percentage of their total nameplate capacity (or a portion of their nameplate capacity intended to meet Massachusetts RPS) into the capacity market, in order for all of the delivered output of the generators to qualify for RECs. Although the verification would be simpler than the previous option, DOER would have to set different minimums for different types of generators. DOER would need to determine a "reasonable" minimum percentage, likely through a stakeholder process. The minimum percentage for intermittent generators, such as wind and solar, can be zero, if DOER so chooses.

Once set, the requirement is clear and unambiguous, thereby making this option easier for DOER to administer than the prior two options. However, appropriate levels for a minimum percentage will be of great debate among stakeholders.

Issue III:

Should an import capacity supply obligation be required to be backed by a renewable energy asset?

Option 1: Backed by Renewable Generator Only

Section 105(c)(3) states that the generator "commits the renewable generating source as a committed capacity resource for the applicable annual period", which implies that the renewable generator must be the capacity resource. This is feasible since adjacent control areas either require or have capability for resource-backed capacity, though HQ capacity resources are all system-backed at this time.

The requirement would be more stringent than what ISO-NE requires of import resources presently.

Option 2: Backed by Any Capacity Resource

This option would allow the requirement to be met as long as there is a contractual agreement between an external renewable generator seeking Massachusetts RPS eligibility and an external capacity resource for an equivalent amount (as determined by previous section) of capacity to be committed in the FCM. This might not provide incremental capacity benefits if generators can piggy-back on existing generators for capacity, but it can provide "reliable" capacity and potentially reduce the risk that intermittent generators face. It would also allow external renewable resources to transfer its obligation to another resource at some time during the capacity period, but still be considered a qualified resource by virtue of obtaining the capacity obligation initially.

Since backing by other resources may not comply with the Act, DOER would need to recommend an amendment.

Option 3: Backed by All ISO-NE Import Backing Methods

ISO rules do not dictate the method of documenting how a resource is backed. To ISO-NE, import resources are transactions not generators. To qualify as an import resource, ISO-NE requires documentation proving that the resource is (1) system-backed; (2) backed with its own asset; or (3) backed with contracted assets.

Generators located in New York and New Brunswick do not have access to system-backed capacity. Hydro Quebec can back its own resources with system power. This presents some disparity between projects in different control areas, in terms of the number of options available for backing their capacity supply obligations. Also, this would not directly comply with the Act, so DOER would need to recommend an amendment where the issue of backing is more aligned with ISO-NE standards.

Issue IV:

Should internal generators also have to commit their capacity on a comparable basis?

Option 1: External Resources Only

Based on the current reading of the Act, Section 105(c) applies only to renewable generators importing energy to New England. However, this would result in disparate treatment of internal and external generators—internal generators have an "option" to participate in the capacity market but external generators have an added "requirement" to provide capacity—a market product separate from energy and RECs—or forfeit participation in the Massachusetts RPS. The requirement of having a capacity obligation poses increased risks and costs for external generators that internal generators do not necessarily face.

Option 2: All Renewable Generators

Even if all renewable generators are subject to a capacity requirement, under current FCM rules there continues to be disparate treatment of internal and external resources. ISO Tariff rules for the FCM impose more stringent requirements and penalities on external (intermittent) resources than internal intermittent resources (but may be somewhat justified given ISO-NE's ability to monitor internal generators but not external). For example, internal intermittent generators still do not need to offer Day Ahead and face no penalties if they are not available during shortage events. Moreover, new external resources face the added risk of receiving only one-year obligations, while new internal resources can opt to receive five-year commitments in the FCM.

Since rules for internal intermittent generators are less prescriptive, most existing renewable generators in ISO-NE have already committed capacity to the FCA1 and plan to for FCA2. Therefore, requiring all renewable generators to participate under current FCM rules might not significantly increase capacity commitments over Option 1.

Option 3: Wait for More Similar Treatment of Internal and External Resources

As a third option, DOER can wait to develop regulations around Section 105(c) until such time the ISO Tariff rules for FCM are more specific for external intermittent resources or the rules are more similar between internal and external intermittent resources.

DOER could contribute to the ISO-NE revision process for FCM rules for external intermittent and internal intermittent resources—something currently being considered by ISO-NE. However, this process would likely be lengthy, involving many stakeholders, Moreover, any rule changes would require a ruling by FERC, which would delay implementation of the requirements and increase uncertainty for developers with external projects under development when considering investment options. The resulting rules, however, may provide for more similar treatment of external and internal resources.

Option 4: Require Only Non-Intermittent Generators to Comply

This option alleviates the uncertainty and risks intermittent generators face in complying with the capacity obligation. However, the increased contribution to capacity for ISO-NE will likely be minimal since so many renewable resources (under ISO-NE FCM) fall into the intermittent category, including some biomass and LFG projects. (See Table 13). On the other hand, external intermittent generators in total are not likely to make a substantial incremental contribution to capacity in the region either (See Table 17).

Option 5: Determine Not Feasible

DOER can determine that it is not feasible to implement such a requirement equitably, without undue discrimination.

II – 2 Section 105(e): Proposed Netting of Exports Requirement

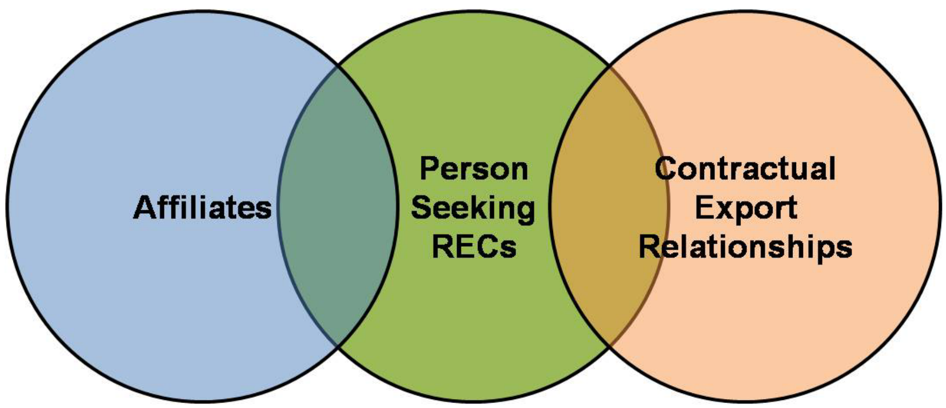
2.1. Implications of Proposed Requirement

2.1.1 Associated Parties

In order to meet the proposed requirements of Section 105(e), RECs must be reduced by any exports of energy from the ISO-NE control area made by any of the following persons:

- The person seeking renewable portfolio standard credit for such renewable energy.
- Any affiliate of such person.
- Any other person under contract with such person to export energy from the ISO-NE control area and deliver such energy directly or indirectly to such person.

Figure 14: Applicable Parties for Netting of Exports



The term "renewable portfolio standard credit" is not defined in the Act and may result in different interpretations of who the "person" claiming credit is, whether it is the person that claims the import REC in the NEPOOL GIS system or the person using the REC to meet its RPS requirements. Our interpretation of "the person seeking renewable portfolio standard credit" is the Market Participant (or NEPOOL Account Holder) that is responsible for verifying and claiming the RECs as part of the NEPOOL-GIS REC creation process. In this case, the Market Participant may not just be the renewable generator. The Market Participant seeking RECs may also be the agent for the renewable generator, a power marketer who purchased the renewable energy in the adjacent control area, or a load serving entity who imported the renewable energy for RPS compliance. The discussions below assume the applicable "person" is the Market Participant.

Since the term "affiliates" is not defined in the Act, there are a few avenues in defining affiliates. One avenue is to use the affiliation definition as described in the NEPOOL GIS rules to flag affiliates.[80] Another avenue is to use the association of affiliates through ISO-NE's Market Participant registration process. In both cases, the definitions of affiliates overlap within the NEPOOL GIS rules as follows:

> *(i) one Account Holder owns, directly or indirectly, 10% or more of the voting stock or other equity interest in the other Account Holder;*
>
> *(ii) 10% or more of the voting stock or other equity interests in both Account Holders are owned, directly or indirectly, by the same person or entity; or*
>
> *(iii) one such Account Holder is a natural person, and such Account Holder or a member of such Account Holder's immediate family is an officer, director, partner, employee or representative of the other Account Holder.*

The third group specified in Section 105(e) may include any entity that has a contractual relationship with the person seeking RECs, by exporting to that person. It is unclear what is meant by "delivered directly or indirectly" to the person seeking RECs, thus the type of contracts would need to be defined more specifically.

As the law is currently written, the netting of exports is associated not only with the person that is seeking the RECs, but also its affiliates and any other person under contract to export the energy to such person. This may have far-reaching, unintended consequences, where transactions unrelated to the scheduling and delivery of renewable energy would be used to penalize the person seeking RECs, which will be discussed further in later sections.

The apparent intent of Section 105(e) is to prevent what is unofficially termed as "greenwashing" or "round-tripping." Greenwashing, in this context, is the process of importing renewable energy into New England to create RECs, while simultaneously exporting the same or a similar quantity of system energy out of New England, resulting in no incremental energy contribution to New England. However, it is not possible to determine that this is happening using publicly available information.

In considering hypothetical scenarios in which greenwashing may occur for economic gain, no scenario could be devised where greenwashing would take place from a commercial or economic perspective and an otherwise economically justified transaction would not take place, except for an extreme situation in which this may occur. To begin, assuming functioning competitive markets in ISO-NE and surrounding control areas, energy will flow from lower cost areas to higher cost areas.

(Scenario A) ISO-NE is Higher Value: To the extent that a neighboring control area has prices that are lower than ISO-NE prices, both renewable energy and other system power will flow into New England. It is highly unlikely that the same importer that was paid a higher price for its delivered energy would also, simultaneously, buy energy in the

[80] New England Power Pool Generation Information System – Operating Rules, 1/1/2008, p. 8. Rule 2.2

higher cost area and export it out of New England during these periods to sell in a lower value area, while potentially incurring transmission costs. To the extent that the Market Participant importing the renewable energy, which was paid the higher energy price, also had a load obligation in the lower cost neighboring control area, the more economic option is to buy system power from that lower cost area to serve the load, rather than exporting from New England. Exporting from a higher cost area to a lower cost area, while incurring additional transmission charges,[81] is not commercially sound. This is the more common state of the market between New England and its surrounding control areas as evidenced by a higher frequency of net imports rather than exports.

(Scenario B) ISO-NE is Lower Value Area: On occasions when New England is the lower value area, then exports from New England would occur as the natural state of the market based simply on economics, regardless of whether the renewable generator is importing energy into New England to satisfy its REC requirement. In other words, the fact that the price is lower in New England than outside the region would motivate an economic decision by someone, whether it is the renewable generator (or its agent) or another un-affiliated party, to export "system energy" until such time it is not economical. Therefore, restricting the export of energy by the person seeking credit for RECs (or affiliates and contractual agreements) does not prevent the export of energy by another un-affiliated party to achieve an economic gain.

(Scenario C) Amount of Renewable Energy Imports Exceeds the Transfer Limit: This last scenario may occur under extreme conditions when the available net transfer capability into New England (in the Real Time) is consistently being exceeded and the entire net transfer capability of the interface is being used by self-scheduled (zero price) energy imports. Under this scenario, in order for a market participant importing renewable energy to ensure that all of the renewable energy is "delivered" into ISO-NE to receive the associated REC revenue, the market participant would also self-schedule an export of some offsetting volume over the same interface. Under the current market rules and operating practices of ISO-NE, the transfer in the opposite direction of the transmission congestion allows additional imports to be "delivered" into New England by effectively increasing the import limit. As an example to illustrate the situation, suppose a Market Participant wishes to import 200 megawatts of renewable energy into New England from New York, but because of the above conditions, there is no more transfer capability. The Market Participant could self-schedule (zero price bid) the 200 megawatts of renewable import and also self-schedule ($999/MWh offer) 200 megawatts of export of system energy for the same hour. During the settlement process ISO-NE would recognize all 200 megawatts of the import as having been delivered into ISO-NE and account for 200 megawatts of exports. Both transactions would have NERC eTags associated with them. ISO-NE would then provide the import information to NEPOOL-GIS for verification of RECs. NEPOOL-GIS will also track the export.

On the surface, this "intentional" expansion of import capacity through scheduling simultaneous exports may appear to be a form of greenwashing. However, it is still not

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[81] Applicable to exports to Canadian control areas.

possible to distinguish such a behavior from otherwise economic market transactions, because the various interfaces (in aggregate) often have imports in excess of transfer limits with simultaneous exports occurring as part of market transactions (see Figure 5). The difficulty to separate out "greenwashing" and economic market transactions is especially true if such exports were bundled with other transactions. Furthermore, there are a limited number of hours in which congestion occurs in Real Time across the various external interfaces (see Table 14). Even if congestion on the tie lines during the Real Time increases in the future, most renewable energy is self-scheduled into New England (especially energy from intermittent resources) and self-scheduled energy clears first in the Real Time market because it has zero cost, thereby serving to lower the cost of imported power and providing price-related benefits to New England ratepayers. As described above, the only time simultaneous exports would be scheduled is if all the imports are self-scheduled (zero price) and there is no incremental net import capability, which would be highly unlikely. Lastly, the "exported" energy will need to be "consumed" somehow within the adjacent control area, which would effectively back-down or displace marginal units in these control areas. While the New York system can readily absorb the "exported" energy, it is debatable whether the Canadian control areas would be able to do so to such a large degree. Thus, the magnitude of the simultaneous exports may be limited by the ability of the receiving control area to absorb the power.

If the concern related to "greenwashing" is that, at some point in the future, the scenario, where net transfer limits are consistently being exceeded and imports that self schedule are the only imports on that line, results in the total hourly amount of RECs exceeding the transfer limit, then DOER may want to seek an alternative accounting method rather than netting exports. For example, if a line has a transfer limit of 1500 megawatts and 2000 megawatts of renewable imports are receiving RECs for that hour, then the RECs for all the renewable imports would be proportionally reduced to a total 1500 megawatthours to reflect what was physically delivered into New England.

2.2. Technical Feasibility

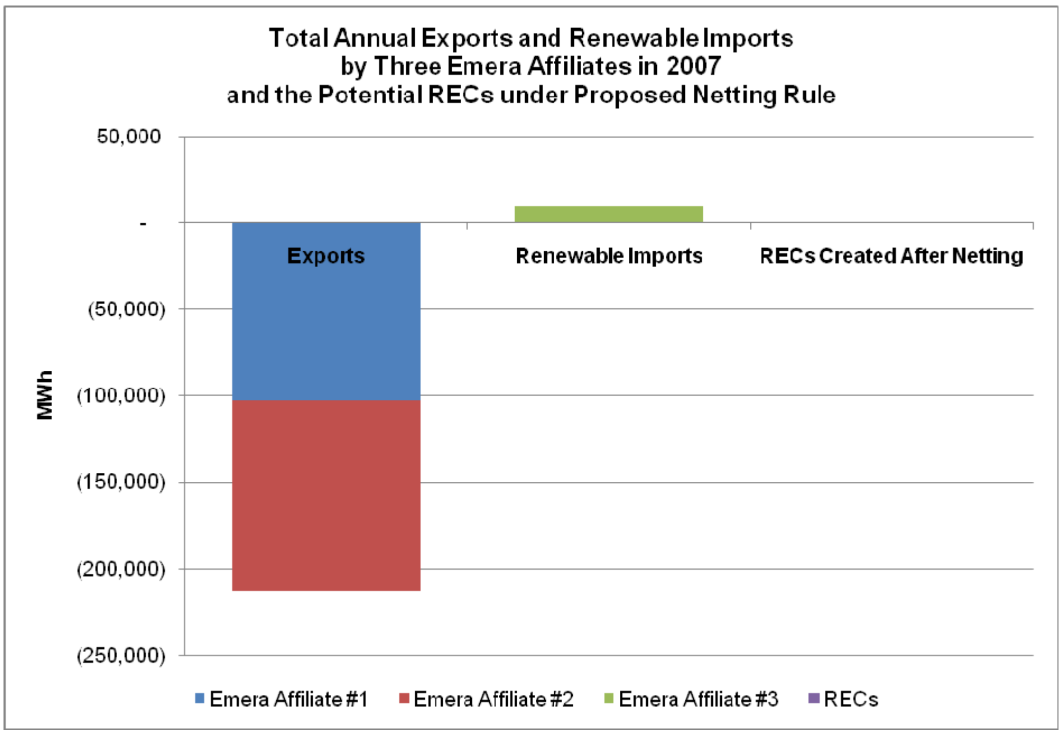
In researching the technical feasibility of obtaining the data to address Section 105(e), we start with the most complex issue of netting exports of all of the different parties specified in the law against the RECs of the person seeking credit for the RECs.

To start, it is not feasible to develop priority rules equitably to determine which affiliates' renewable energy get netted. For example, if Affiliate A imports 100 megawatt-hours of renewable energy; Affiliate B generates 200 megawatt-hours of renewable energy in New England and exports 100 megawatt-hours of system energy; and Contracted Entity C exports 50 megawatt-hours of system energy to Affiliate A; there does not appear to be an equitable way to reduce the RECs for Affiliates A and B that are seeking RECs with the exports of B and C.

Furthermore, agents, such as Emera, who have set up separate entities to provide transaction services for separate clients, face serious confidentiality issues if one transaction of one entity offsets another transaction of a separate entity. Emera Energy

Services[82] indicated that they have set up a number of affiliate entities for the purposes of serving their customers individually. Implementing the netting provision across affiliates is particularly problematic for agents like Emera Energy Services and their customers. If one of these agent's customers wants to export renewable energy to New England from a resource in Canada, that customer is at risk for losing some or potentially all RECs due to netting, if another of the agent's customers wants to export power from New England at the same time (without prior knowledge of the imported renewable energy and is only interested in getting energy to serve its own obligations.) As an example, looking at a year's worth of data for Emera's various affiliates, we see that the relatively small amount of RECs would be dwarfed by the exports of affiliates (see Figure 15), resulting in no net RECs for the affiliate importing RECs.

Figure 15: Example of Affiliate Transactions



Source: NEPOOL-GIS Data

Furthermore, we determined that it is not feasible to track contractual arrangements through market-based data sources due to a lack of data availability. Through interviews

[82] Emera Energy Services schedules and imports renewable energy into New England on behalf of a number of renewable resource owners in Canada. Emera Energy, in fact, only transacts power on behalf of others, meaning they do not trade power for their own account. The reason for establishing separate legal entities is that the ISO-NE settlement system was not able to keep the trading activity and hence the charges and credits for Emera's customers separate unless they were each a separate legal entity. Emera Energy Services made the business decision to setup distinct legal entities as affiliates in order to be able to keep the transactions of one of their customers from affecting their other customers.

with various personnel at ISO-NE, APX, and our own independent research, it appears that the data necessary to track contractual relationships would not be available.

Information contained in a NERC eTag was considered as a potential source for the data. However, the information in the eTag is insufficient for the purposes of identifying and tracking contractual relationships. In addition, only those who are a party to the NERC eTag, such as ISO-NE, would be allowed access to the data in the NERC eTag. DOER would not be considered a party and neither would APX, who is the NEPOOL GIS administrator. The NEPOOL GIS currently receives market data from ISO-NE, but ISO-NE does not believe they have the legal authority to distribute eTag data as that data are not the property of the system operator. DOER would have to require market participants to grant permission for either DOER or APX to review the eTag information for all of their transactions, which poses major commercial confidentiality problems.

The ISO-NE market and settlement system was also considered as a possible source of data to implement netting across contracted parties. However, ISO-NE reports that they do not have the data to track contractual relationships nor do they even have the legal authority to ask market participants about their contractual relationships.

For all the reasons listed above, we believe it will not be feasible to net exports across affiliates and contractual arrangements.

It is feasible to track and net exports for individual NEPOOL participants only. Netting exports by the same person seeking credit for RECs is the most straightforward option, since in-region generation, imports, and exports are tracked through NEPOOL GIS for individual Market Participants. However, this does not prevent a person from setting up a separate entity to export the same amount of energy simultaneously. ,

2.3. *Practical Feasibility*

Though it is technically possible to net exports associated with the person seeking RECs, issues arise when this netting is applied to larger market participants that import renewable energy and have their own trading operations. The function of the trading operation is to buy and sell power in and across various markets in order to take advantage of any price opportunities or differences and earn a profit. In the course of normal trading operations, the larger market participants will be both importing energy and exporting energy depending on the relative economics of ISO-NE prices and the prices in surrounding markets. In addition, import and export transactions can be of a wide variety of durations (hourly or less to monthly to multi-year); and can be committed well in-advance of the import of the renewable energy.

In addition, there is typically a separate group that is responsible for the scheduling and delivery of energy from renewable resources in their portfolio. The trading operation and the group scheduling the renewable energy are likely operating independently of each other. Thus, netting the megawatt-hours of the renewable scheduling group with any exports transacted by the trading group, despite the fact that they were performed independently and for different commercial reasons, seems unreasonable unless separate legal entities are created to import renewable power only separate from trading desks.

Thus, if netting of exports against the person seeking RECs were to be implemented, one solution for renewable generators or their agents would be to create separate legal entities (from exporting or trading entities) to schedule the renewable energy into New England. Establishing separate entities to import renewable energy may entail increased legal and administrative costs to agents serving renewable generators, which would be passed through to their clients, though the costs will not be prohibitive. This may become unduly burdensome for smaller generators, though there are agents that currently provide this specific function.

Netting of exports for the person seeking credit for the RECs will ensure, at a minimum, that the energy imported is not being exported simultaneously by the person seeking credit for the RECs. It does not address scenarios where other affiliates are exporting energy simultaneously, either unknowingly or knowingly.

2.4. Implementation Issues and Options

If DOER sought to implement Section 105(e), it would need to decide two key issues:

- *Over what time frame should netting occur?*
- *Which exports are to be netted from the RECs for which a person is seeking credit?*

Issue I:

Over what time frame should netting occur?

Option 1: Hourly

It is important to understand that electricity generated does NOT stay in the grid for very long,meaning the electrons are consumed almost immediately somewhere by load. If the goal is to ensure green energy coming into (or being generated in) New England is not being exported simultaneously, hourly netting is the most logical option. Since exports are scheduled hourly, this is the smallest increment of time for which data is available for APX to track through NEPOOL GIS.

Option 2: Time Interval Greater Than Hourly

Any other duration would not match with the physics of electricity or the marginal cost of generating that electricity. This means electricity generated in one hour is not the same as electricity generated at a later period in time, both physically and economically. Additionally, by the same rationale as the current DOER regulations for imports require hourly matching of delivery and generation, it would be inconsistent to offset an import with an export occurring at a different time.

Issue II:

Which exports are to be netted from the RECs for which a person is seeking credit?

Option 1: Net Exports of All Types of Associations

As the law is currently written, the netting of exports is associated not only with the person that is seeking the RECs, but also its affiliates and any other person under contract to export the energy to such person. As described above, this option is not feasible because it is not possible to net exports across affiliates in an equitable manner and there is not sufficient non-confidential data to track contractual obligations and the parties involved.

Option 2: Net Exports of Affiliates and Person Seeking Credit

As described above, this option is not feasible because it is not possible to net exports across affiliates in an equitable manner.

Option 3: Net Exports of Person Seeking Credit

Since offsetting imported RECs with un-related exports by the same Market Participant would unfairly penalize the person importing RECs for conducting normal business, the result may be that a separate legal entity would be established only to schedule the renewable energy and claim the RECs. However, this does not prevent a person from setting up a separate entity to export the same amount of energy simultaneously, and, thereby, being ineffectual in mitigating "greenwashing."

Option 4: Generators Provide Self-Attestation

As part of the qualification application of renewable generators, DOER can require the applicants (or the Market Participant representing them) to self-attest that, to their knowledge, the renewable energy delivered to New England will not be exported by themselves, their affiliates, or agents scheduling their renewable energy for them. There would not be any additional tracking or netting required. However, this option may feature involved investigation and confirmation processes, if self-attestation statements are challenged or questioned by parties. DOER will need to request extensive amounts of confidential data from "person seeking RECs" or receive permission from that person to allow APX to provide all import and export data, in order to verify that no exports were occurring simultaneously for the purposes of "greenwashing." In this case, DOER may want to set-up a very specific threshold of proof for the challenger to meet before the investigation into the person seeking RECs is initiated.

However, as explained previously, it would still be difficult, if not impossible, to distinguish between an export transaction scheduled for economic or contractual obligations versus a transaction used to "increase" transfer capability into New England, especially if they are bundled with other export transactions.

Option 5: DOER Deems Not Feasible

DOER may deem the implementation of the netting requirement not feasible on the basis that the law (applicable to person requesting the REC, affiliates, and any other person under contract with such person) cannot be implemented in its entirety.

Furthermore, as stated before, we do not believe that netting of exports for just those persons seeking RECs, using specialized agents, will prevent any simultaneous exports of energy for economic reasons.

Conclusions

Section 105(c)

In conclusion, we find that implementing Section 105(c) is not feasible in the near-term if immediate participation in the ISO-NE Forward Capacity Market is part of the requirement. Under certain options that help mitigate risk exposure for external renewable generators, such as delaying implementation of the proposed requirement until the fourth Forward Capacity Auction (2013/2014), Section 105(c) may be feasible. We also determined that the legislation as written does apply only to external renewable generators and that the import capacity obligation must be backed by the same resources seeking RPS qualification. DOER may propose changes to the legislation, but the following discussions assume that Section 105(c) applies to only external renewable generators. Because of the disparate treatment of external renewable generators and internal renewable generators, within the legislation and within ISO-NE rules for capacity resources, DOER will need to determine whether this will make the requirement infeasible.

Should DOER decide to proceed with the implementation of Section 105(c), DOER will need to establish specific regulations for what is considered a "committed capacity resource," and will need additional staff to verify capacity commitments during the RPS qualification process. There will be increased costs and risks for external renewable generators, which may limit the number of future imports of renewable energy.

The table below is a summary of some of the more feasible composite options or paths to implement Section 105(c) for DOER's consideration (see Appendix for more detailed table). With regards to the issue of timing of the implementation and participation in the FCM, the two most feasible options are: (1) to delay the start of the requirement until the forth FCA and not penalize pro-rated capacity; or (2) start the requirement now but developing a capacity obligation outside of the FCM construct. As far as capacity commitment levels required of different renewable generators, we present the four best options: (1) same as ISO-NE standards for intermittent and non-intermittent generators; (2) DOER develops different levels of commitment for different resource types based on their typical capacity potential; (3) DOER sets the capacity requirement for intermittent generators to zero; or (4) the level is as available and delivered into New England during "shortage events."

DOER will want to weigh the level of time and effort needed to verify and monitor generators against the level of risk mitigation afforded to external generators. Additionally, for paths that are outside of the Forward Capacity Market construct, external generators would not be providing additional capacity to ISO-NE's planning process nor would they contribute to any control area's capacity planning process, if required to de-list.

Of the various paths presented in the table below, Path C, where only non-intermittent generators would be required to participate in the FCM and only starting with the fourth

FCM, appears to be the most workable, in terms of relieving risk for external intermittent generators and allowing DOER's regulatory and monitoring processes to be more straightforward. Furthermore, ISO-NE will be able to include more reliable capacity in its planning process, though few generators may be considered non-intermittent, depending on whether DOER defines intermittent generators narrowly (wind and solar only) or more broadly (no control over power output). The latter definition will likely include most external renewable generators, which would result in little capacity contribution.

Alternatively, since none of the proposed paths would result in any significant increase in capacity, DOER may decide it is not worthwhile to proceed with implementing the proposed capacity requirement if the aim of impacting the capacity market or providing more resource adequacy is of prime importance and is not being fulfilled.

Table 18: Summary of Preferred Paths for Implementation of Section 105(c)

	Preferred Paths	A (FCM ISO)	B (FCM Min)	C (FCM Non-Int Only)	D (Outside FCM Min)	E (Outside FCM Non-Int Only)	F (Outside of FCM Output)
	I. Timing and FCM	*FCA4 (and beyond) with Pro-rated Eligibility*			*Capacity Obligation Outside of FCM*		
	II. Committed Capacity Quantity	*Same as ISO Rules for Internal*	*Set Minimum Requirements by Resource Type*	*Set Minimum For Intermittent to Zero*	*Set Minimum Requirements by Resource Type*	*Set Minimum For Intermittent to Zero*	*Generated and Delivered Output*
Administrative Requirements	APX conducts additional verification of REC creation	X[1]	X[1]	X[1]	X[2]	X[2]	X[2]
	DOER establishes minimum capacity commitment levels		X	X	X	X	
	DOER verifies individual applicant's capability to provide capacity	X					
	DOER monitors and checks for availability during shortage events				X	X	X[3]
	DOER monitors and checks for availability during shortage events	O[4]	O[4]	O[4]	X	X	X
Market Participants Costs and Risks	MP must qualify and participate in the FCM.	X	X	X			
	MP forgoes any potential capacity revenue				X	X	X
	Intermittent Generators face performance risks	X	X		X		
REC Supply Impact	Reduction to import REC supply	X	X		X		
Capacity Market Impact	Included in ISO-NE Capacity Planning	X	X	X			
	No impact on FCM (quantity and price)			X[6]	X	X	X
	Reliance on intermittent capacity for reliability[5]	X	X				

1. Request monthly capacity payment receipts as verification that resource is participating fully in the FCM.
2. Check hourly output and delivery against shortage events to determine the magnitude of delivery.
3. No need to establish a threshold "availability" requirement, but need to determine if outages were forced or unforced outages.
4. No need to penalize for availability since FCM has penalties in place, but DOER has option to impose additional penalties.
5. Relying on external intermittent generators for capacity may degrade reliability over time.
6. Adds very little incremental capacity to FCM, thus negligible price suppression benefits

X=Applicable, O=Optional

Section 105(e)

For Section 105(e), the law applies to exports made by the person seeking renewable portfolio credit. "Renewable portfolio standard credit" is not defined in the Act and may have multiple interpretations. Our interpretation of "the person seeking renewable portfolio standard credit" is the Market Participant (or NEPOOL Participant) that is responsible for verifying and claiming the RECs as part of the NEPOOL-GIS REC creation process. The discussions below assume this interpretation of the applicable "person."

We find that it is infeasible to implement Section 105(e) in its entirety, where "any exports of energy from the ISO-NE control area made by the person seeking renewable portfolio credit for such renewable energy or any affiliate of such person, or any other person under contract with such person to export energy from the ISO-NE control area and deliver such energy directly or indirectly to such person." To start, it is not feasible to net exports for affiliates and persons with whom there are contracts for export because any approach to net un-related exports against REC imports would be arbitrary, if not commercially damaging,. However, we believe it is feasible to net the exports associated with the person seeking RECs. DOER may want to proceed to net exports against only the subset of persons seeking RECs, but, as stated before, we do not believe this will prevent any simultaneous exports of energy for economic reasons or any other reasons.

Alternatively, DOER may be satisfied with the generator self-attesting that the energy associated with the RECs is not being exported by the person seeking RECs or its affiliates, and there are no contracts with third-parties to export the energy. However, if contested, DOER will need to request extensive amounts of data from the generator to verify that no exports are occurring simultaneously for the purposes of "greenwashing." As explained previously, it would be difficult, if not impossible, to distinguish between an export transaction scheduled for economic or contractual obligations versus a transaction used to "increase" transfer capability into New England, especially if the exports are bundled with other transactions.

Therefore, because neither of the options will be effective in capturing exports associated with "greenwashing," DOER may determine that it is not practically feasible to implement Section 105(e) in its entirety and, therefore, no action needs to be taken or alternative policies to address the issue of "greenwashing" may be pursued separately.

Appendix

Definition of Affiliate and Related Person from 2nd Restated NEPOOL Agreement: Section 1 of the 2d RNA provides that, "A Related Person of a Participant is (a) for all Participants, either (i) a corporation, partnership, business trust or other business organization 10% or more of the stock or equity interest in which is owned directly or indirectly by, or is under common control with, the Participant, or (ii) a corporation, partnership, business trust or other business organization which owns directly or indirectly 10% or more of the stock or other equity interest in the Participant, or (iii) a corporation, partnership, business trust or other business organization 10% or more of the stock or other equity interest in which is owned directly or indirectly by a corporation, partnership, business trust or other business organization which also owns 10% or more of the stock or other equity interest in the Participant , or (iv) a natural person, or a member of such natural person's immediate family, who is, or within the last 12 months has been, an officer, director, partner, employee, or representative in NEPOOL activities of, or natural person having a material ongoing business or professional relationship directly related to NEPOOL activities with, the Participant or any corporation, partnership, business trust or other business organization related to the Participant pursuant to clauses (i), (ii) or (iii) of this Section (a); and (b) for all End User Participants which are also natural persons, a Related Person is (i) a member of such End User's immediate family, or (ii) a Participant and any corporation, partnership, business trust, or other business organization related to the Participant pursuant to clauses (i), (ii) or (iii) of Section (a), of which such End User Participant, or a member of such End User Participant's immediate family, is, or within the last twelve (12) months has been, an officer, director, partner, or employee of, or with which an individual End User Participant has, or within the last twelve (12) months had, a material ongoing business or professional relationship directly related to NEPOOL activities, or (iii) another Participant which, within the last twelve (12) months, has paid a portion of the End User Participant's expenses under Section 19 of this Agreement, or (iv) a corporation, partnership, business trust or other business organization in which the End User Participant owns stock and/or equity with a fair market value in excess of $50,000. (c) Notwithstanding the foregoing, for the purposes of this definition, an individual shall not be deemed to have or had a material on-going business relationship directly related to NEPOOL activities with any corporation, partnership, business trust, other business organization or Publicly Owned Entity solely as a result of being served, as a customer, with electricity or gas." <u>and</u> pursuant to the ISO's Code of Conduct, Affiliate "with respect to an entity, means any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, or other form of entity, directly or indirectly Controlling, Controlled by, or under common Control with, such entity. The term "Control" means the possession, directly or indirectly, of the power to direct the management or policies of an entity. A voting interest of ten percent or more creates a rebuttable presumption of control."

Summary Paths

Summary of Preferred Paths for Implementation of Section 105(c)

Preferred Paths		A (FCM ISO)	B (FCM Min)	C (FCM Non-Int Only)
I. Timing and FCM		*FCA4 (and beyond) with Pro-rated Eligibility*		
II. Committed Capacity Quantity		*Same as ISO Rules for Internal*	*Set Minimum Requirements by Resource Type*	*Set Minimum For Intermittent to Zero*
Administrative Requirements	APX conducts additional verification of REC creation	Request monthly capacity payment receipts as verfication that resource is participating fully in the FCM.	Request monthly capacity payment receipts as verfication that resource is participating fully in the FCM.	Request monthly capacity payment receipts as verfication that resource is participating fully in the FCM.
	DOER establishes mininum capacity commitment levels	Use ISO-NE standards	Need to establish different limits for different resources.	Need to establish different limits for different resources. Zero for intermittent.
	DOER verifies individual applicant's capability	Since ISO-NE is not checking for the maximum capability of a resource, so DOER must verify and review applicant's capability	No need for verification as long as minimum requirement is met through ISO-NE FCM	No need for verification as long as minimum requirement is met through ISO-NE FCM
	DOER monitors and checks for availability during shortage events	Availability with be monitored by ISO-NE	Availability with be monitored by ISO-NE	Availability with be monitored by ISO-NE
	DOER penalizes unavailability incidents through withholding some RECs	No need to penalize for availability since FCM has penalties in place, but DOER has option to impose additional penalties.	No need to penalize for availability since FCM has penalties in place, but DOER has option to impose additional penalties.	No need to penalize for availability since FCM has penalties in place, but DOER has option to impose additional penalties.
Market Participants Costs and Risks	MP must qualify and participate in the FCM.	Submit acceptance of capacity obligation by ISO-NE as proof of being a commited capacity resource.	Submit acceptance of capacity obligation by ISO-NE as proof of being a commited capacity resource.	Submit acceptance of capacity obligation by ISO-NE as proof of being a commited capacity resource.
	MP forgoes any potential capacity revenue	Participants receive capacity revenue	Participants receive capacity revenue	Participants receive capacity revenue
	Intermittent Generators faces performance risks	If intermittent, ISO rules mean capacity commitment is less than nameplate capacity, so risks are lower	A pre-set minimum capacity commitment would help to minimize risks if set low for intermittent generators	Only non-intermittent generators would have to participate in the FCM. Less risk because they are dispatchable units.
REC Supply Impact	Reduction to import REC supply	May deter some intermittent generators from participating, reducing the number of imported RECs, but should not be significant because risks are relatively low.	May deter some intermittent generators from participating, reducing the number of imported RECs, but should not be significant because risks are relatively low.	Likely not to alter REC supply
Capacity Market Impact	Included in ISO-NE Capacity Planning	Allows ISO-NE to plan around an expectation of import capacity from renewable generators, though relatively small amount of resulting incremental capacity obligations.	Allows ISO-NE to plan around an expectation of import capacity from renewable generators, though relatively small amount of resulting incremental capacity obligations.	Allows ISO-NE to plan around an expectation of import capacity from renewable generators, though relatively small amount of resulting incremental capacity obligations.
	No impact on FCM (quantity and price)	Potential for minor impact on capacity market in terms of quantity and price suppression	Potential for minor impact on capacity market in terms of quantity and price suppression	The incremental capacity obligations will be less if intermittent generators are not required to participate. Adds very little incremental capacity to FCM, thus negligible price suppression benefits.
	Reliance on intermittent capacity	Relying on external intermittent generators for capacity may degrade reliability over time.	Relying on external intermittent generators for capacity may degrade reliability over time.	Non-intermittent generators will provide better reliability.

Summary of Preferred Paths for Implementation of Section 105(c) – cont'd.

Preferred Paths		**D (Outside FCM Min)**	**E (Outside FCM Non-Int Only)**	**F (Outside of FCM Output)**
I. Timing and FCM		*Capacity Obligation Outside of FCM*		
II. Committed Capacity Quantity		*Set Minimum Requirements by Resource Type*	*Set Minimum For Intermittent to Zero*	*Generated and Delivered Output*
Administrative Requirements	APX conducts additional verification of REC creation	Check hourly output and delivery against shortage events to determine the magnitude of delivery.	Check hourly output and delivery against shortage events to determine the magnitude of delivery.	Check hourly output and delivery against shortage events to determine the magnitude of delivery.
	DOER establishes mininum capacity commitment levels	Need to establish different limits for different resources.	Need to establish different limits for different resources. Zero for intermittent.	No need to establish minimum requirement.
	DOER verifies individual applicant's capability	No need for verification as long as minimum requirement is being generated and delivered during shortage events.	No need for verification as long as minimum requirement is being generated and delivered during shortage events.	No need for verification as long as all output is being delivered during shortage events.
	DOER monitors and checks for availability during shortage events	DOER monitors and checks for availability during shortage events	DOER monitors and checks for availability during shortage events	No need to establish a threshhold "availability" requirement, but need to determine if outages are forced or unforced outages.
	DOER penalizes unavailability incidents through withholding some RECs	Must establish penalties if resource underperforms relative to minimum, which may be reflected in the amount of RECs that get RPS eligibility	Must establish penalties if resource underperforms relative to minimum, which may be reflected in the amount of RECs that get RPS eligibility	As long as output is delivered to New England in a shortage event, there is no penalties. However, penalties would still need to be considered when there is output buy no delivery to New England.
Market Participants Costs and Risks	MP must qualify and participate in the FCM.	Do not have to be subject to risks associated with participating in the FCM, but REC penalities for not delivering during a shortage event may be greater than risks associated with the FCM.	Do not have to be subject to risks associated with participating in the FCM, but REC penalities for not delivering during a shortage event may be greater than risks associated with the FCM.	Do not have to be subject to risks associated with participating in the FCM, but REC penalities for not delivering during a shortage event may be greater than risks associated with the FCM.
	MP forgoes any potential capacity revenue	May have to forego capacity revenue from generator's home control area capacity markets if required to de-list.	May have to forego capacity revenue from generator's home control area capacity markets if required to de-list.	May have to forego capacity revenue from generator's home control area capacity markets if required to de-list.
	Intermittent Generators faces performance risks	A pre-set minimum delivery commitment would help to minimize risks if set low for intermittent generators	Only non-intermittent generators would have to participate, so no risk for intermittent generators.	Minimal risk since delivery is only based on output of generator.
REC Supply Impact	Reduction to import REC supply	Depending on penalties set by DOER, generators may not get credit for all RECs delivered, so amount of MA-eligible RECs are reduced	Likely not to alter REC supply, since non-intermittent generators are more able to dispatch during shortage events.	Likely not to alter REC supply
Capacity Market Impact	Included in ISO-NE Capacity Planning	ISO-NE would not recognize and plan with the capacity. If generators are required to de-list from their home control area, no one benefits from its capacity contribution.	ISO-NE would not recognize and plan with the capacity. If generators are required to de-list from their home control area, no one benefits from its capacity contribution.	ISO-NE would not recognize and plan with the capacity. If generators are required to de-list from their home control area, no one benefits from its capacity contribution.
	No impact on FCM (quantity and price)	No participation in ISO-NE FCM, so no impact on market	No participation in ISO-NE FCM, so no impact on market	No participation in ISO-NE FCM, so no impact on market
	Reliance on intermittent capacity	No participation in ISO-NE FCM, so no impact on reliability	No participation in ISO-NE FCM, so no impact on reliability	No participation in ISO-NE FCM, so no impact on reliability